IN THE MATTER OF

The Utilities Commission Act (the Act)

and

A Request of the Lieutenant Governor in Council
of the Province of British Columbia
pursuant to Section 5(1) of the Act to the
British Columbia Utilities Commission (the Commission)
to Inquire into and Advise on a
Heritage Contract for BC Hydro's Existing Generation Resources,
Stepped Rates and Transmission Access

and

Terms of Reference Issued March 25, 2003 Pursuant to Order in Council 0253 and
Section 5(2) of the Act (Terms of Reference)

and

Order G-23-03 of the Commission Directing BC Hydro to File a Proposal
Regarding a Heritage Contract,
Stepped Rates and Transmission Access

A PROPOSAL BY THE BRITISH COLUMBIA HYDRO AND POWER AUTHORITY REGARDING A HERITAGE CONTRACT, STEPPED RATES AND ACCESS PRINCIPLES

VOLUME 1 OF 2

APRIL 30, 2003

Energy Plan

IMPLEMENTATION

BC hydro

105-03588/

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Executive Summary

BC Hydro's proposal in response to the Terms of Reference issued by the Lieutenant Governor in Council on March 25, 2003 pursuant to Section 5 of the *Utilities Commission Act* is presented in two volumes. Volume 1 outlines a proposal for a Heritage Contract to fulfil Policy Action # 1 identified in the Provincial Government release entitled *Energy for Our Future, a Plan for BC* (the Energy Plan). Volume 2 introduces a new rate structure for large industrial and commercial customers in response to Policy Actions # 14 and 21 in the Energy Plan.

The context of the section 5 inquiry is set out in Section 1.1 of Volume 1. In broad overview, Policy Action # 1 calls for a Heritage Contract which has the effect of locking in the value of existing low-cost generation assets for BC Hydro's ratepayers. Policy Action #2 seeks a continuation of the benefits BC Hydro ratepayers have received from electricity trade. The Heritage Contract proposal presented in Volume 1 does both.

Policy Actions # 14 and 21 in the Energy Plan contemplate the development of a new stepped rate for industrial customers. Volume 2 contains BC Hydro's thinking with respect to the considerations involved in developing such a rate.

Volume 1 – The Heritage Contract Proposal

The Heritage Contract proposal is described in brief in Chapter 2 and elaborated in detail in Chapter 3 of this Volume. Those chapters describe a mechanism that BC Hydro believes will carry into effect the Energy Plan in a way that maximizes the benefits that all of BC Hydro's ratepayers receive from the low-cost Heritage Resources that BC Hydro has built over the last 40 odd years. Rather than summarize the information in those chapters, the executive summary focuses on a number of significant implications of the approach BC Hydro has taken. Those wishing to fully understand the proposal are encouraged to read Chapters 2 and 3.

In designing the Heritage Contract as it has, BC Hydro has had in mind two key public policy objectives, as follows:

(1) Secure, reliable supply: The Heritage Contract should allow BC Hydro to provide a secure, reliable source of electricity for all current and future British Columbians taking service from BC Hydro under the rate schedules listed in Schedule B of the Terms of Reference (the Heritage Beneficiaries) (Energy Plan Policy Actions #3 and #7);

(2) Low electricity rates: The Heritage Contract should allow BC Hydro to: (a) maximize the value of the generating capabilities of the resources within BC Hydro's control and allow BC Hydro to minimize the cost of acquiring resources for Heritage Beneficiaries (Energy Plan Policy Actions #2 and #3); and

(b) provide the capability of the resources listed in Schedule A of the Terms of Reference, together with the related civil works and plant (collectively, the Heritage Resources), on the basis of their embedded cost (Energy Plan Policy Action #1).

In serving these objectives, BC Hydro adopted the following four principles:

(1) The Heritage Contract proposal ought to allocate to the Heritage Beneficiaries only those costs commensurate with the allocation of benefits;

(2) The Heritage Contract proposal should drive economically efficient decisions at the margin for supply, demand, and trade;

(3) The Heritage Contract proposal should be as simple and understandable as possible so that economic incentives will be clear to all participants; and

(4) To maximize system value, those operating the system and those buying and selling power from and for the system should have, to the greatest extent possible, unfettered communications.

The Energy Plan makes it clear that the Heritage Resources are to be owned and operated to benefit the current and future ratepayers of BC Hydro. This requirement has a number of implications.

First, the focus on current and future British Columbians implies that the proposal needs to be structured to confer benefits on new customers, as well as existing ones. A corollary of that implication is that the benefits should be realized by customer classes, as opposed to individual customers. The proposal put forward by BC Hydro and its approach to stepped rate design are both informed by the distinction between conferring an ongoing benefit on all of BC Hydro's ratepayers and providing a once only dividend to those customers who happen to be taking service from BC Hydro at the time the Energy Plan is adopted. BC Hydro does not believe that the government intended an arbitrary allocation of benefits to individual customers.

Second, the Energy Plan also clearly envisages that the ownership and operation of the Heritage Resources by BC Hydro will benefit all classes of customers for an extended period of time. Accordingly, the Heritage Contract proposal is designed to ensure that all customers continue to benefit from the significant operational flexibility that BC Hydro's ample storage capacity permits, and that they pay for supply on an embedded cost basis. A deferral account will be employed in conjunction with the Heritage Contract to smooth the ratepayer impact of variations between the forecast and actual revenue derived from the Heritage Resources each year. This account is fully described in section 3.5 of Volume 1.

An important example of this second implication is the manner in which the proposal deals with the allocation of trade income. The Terms of Reference request that the Commission recommend the appropriate means to allocate all annual trade income received by BC Hydro below $200 million. BC Hydro believes that trade income below $200 million should be allocated to the benefit of ratepayers to ensure that those charged with operating the system are indifferent to whether the value of the system is realized in income from trade or by minimizing the cost of the acquiring energy in the future to serve domestic load. By allocating all trade income to ratepayers, BC Hydro's proposal will ensure that its decisions concerning whether to generate for export or store for future consumption are driven by an unbiased assessment of the income to be obtained from generation at the time the decision is made versus the potential cost of reacquiring energy when it is needed in the future.

The proposal defines trade income in a way that means annual trade income will rarely fall outside the $0 to $200 million range. In the exceptional case where it does, the Province, as BC Hydro's owner, will experience the impact. Thus, where trade income exceeds $200 million per year, BC Hydro may keep the excess for payment to the Province. Where trade income is negative, BC Hydro will absorb the loss and pass on less income to the Province. Thus, the Province incurs the benefits and costs associated with truly exceptional circumstances and ratepayers otherwise obtain whatever income can be derived from trade.

Third, the Heritage Contract proposal is structured to encourage information flow between those charged with operating the system and those who have the responsibility to market its output externally. This structure should form the basis for informed decision-making in all stages of BC Hydro and Powerex's activities. As well, the Heritage Contract proposal does not make it necessary to disturb the present regulatory structures that allows BC Hydro (and Powerex) a relatively free hand to market energy in competitive external markets while ensuring that adequate information is provided to safeguard the interests of ratepayers in regulated domestic markets.

Volume 2 – Stepped Rates and Access Principles

The Terms of Reference request the Commission to make recommendations with respect to the principles that should govern industrial customers' access to transmission and to BC Hydro's generation service where they wish to obtain generation from alternative suppliers. BC Hydro believes that in the short term, and to the extent industrial customers require access to transmission, that access should be on precisely the same terms and conditions as existing wholesale customers. Currently, that occurs pursuant to BC Hydro's Wholesale Transmission Service rate schedules. As described in Section 4.3 of Volume 2, responsibility for those schedules will in future be assumed by a new, separate Crown Corporation. That entity should be responsible for determining the changes, if any, to the terms and conditions of transmission service. In the meantime, the proposal does not require any changes to WTS service.

The ability of industrial customers to choose service from alternate suppliers exposes BC Hydro to some new potentially significant risks. The nature and extent of these risks will depend on the specific design of the stepped rate for those customers. In Volume 2, BC Hydro presents an analysis of alternative stepped rate designs, but recommends that further consultation with stakeholders occur before a design is finalized. BC Hydro believes this consultation and final design process must be allowed to occur before access principles can usefully be developed in response to paragraph 4(c) of the Terms of Reference.

1 Introduction

1.1 *Context of the Inquiry*

On November 25, 2002, the provincial government released *Energy for Our Future: A Plan for BC* (Energy Plan). The Energy Plan has led directly to this proposal through a number of Policy Actions. Policy Action #1 calls for the development of a legislated Heritage Contract. Policy Action #2 calls for ratepayers to continue to benefit from electricity trade. Policy Actions #14 and #21 call for new rate structures under which large industrial and commercial customers are enabled and encouraged to seek supplies of electricity from sources other than BC Hydro. These Policy Actions are reflected in the Terms of Reference issued by the Lieutenant Governor in Council on March 25, 2003 pursuant to section 5 of the *Utilities Commission Act* (the Act). The Terms of Reference are attached at Appendix A.

According to the Terms of Reference:

> "The general purpose of the inquiry is to obtain the Commission's Recommendations on what changes, if any should be made to legislation, regulations, special directions or special directives affecting BC Hydro and/or the Commission in order to implement the Energy Plan in connection with the issues identified in paragraphs 3 and 4 of these Terms of Reference."

Paragraph 3 of the Terms of Reference deals with the Heritage Contract, and paragraph 4 deals with stepped rates and access principles for transmission voltage customers.

In addition, the Terms of Reference direct that:

> "The Commission shall require BC Hydro to file by April 30, 2003 a proposal that identifies the detailed Recommendations and reasons that BC Hydro believes should be contained in the Commission's report . . ."

The Commission's directive to BC Hydro was issued as Order No. G-23-03, and this proposal is responsive to that order. Order G-23-03 is attached at Appendix B.

1.2 *Overview of BC Hydro's Proposal*

1.2.1 Two Distinct Parts

This proposal is set out in two volumes. Volume 1 deals with all aspects of the Heritage Contract as required by paragraph 3 of the Terms of Reference. Volume 2 of the proposal covers paragraph 4 of the Terms of Reference, dealing with stepped rates and the terms and conditions under which transmission voltage customers may obtain access to BC Hydro's transmission system.

Volumes 1 and 2 of the proposal differ in approach. In Volume 1, BC Hydro presents a comprehensive vision of the way in which the Heritage Contract concept should be applied in the specific context of the BC Hydro system. The proposal is intended as a package and each of its elements is inextricably linked with all or some of its other elements. While BC Hydro acknowledges other approaches to establishing a Heritage Contract are possible, it firmly believes that this proposal is the one which best meets the public policy objectives that lie at the heart of the Energy Plan's call for establishment of the Heritage Contract.

On the other hand, when it comes to the design of stepped rates, BC Hydro believes that the Energy Plan's objectives can be accomplished in a variety of ways. However, the choice of methodology will affect the relative position of different customer groups. BC Hydro believes that consultation with BC Hydro's principal stakeholders is the best way to settle on the basic concept and choose the specific terms and conditions to be established in connection with the stepped rates and accompanying access principles. This approach is elaborated in Volume 2.

1.2.2 Context and Principles of the Heritage Contract Proposal

The Energy Plan sets out a number of policy actions which BC Hydro believes assist in defining the objectives of the Heritage Contract. A number of the policy actions bear on the Heritage Contract, but in BC Hydro's view, the public policy objectives that are evidenced in the Energy Plan can be reduced to the following:

(1) Secure, reliable supply: The Heritage Contract should allow BC Hydro to provide a secure, reliable source of electricity for all current and future British Columbians taking service from BC Hydro under the rate schedules listed in Schedule B of the Terms of Reference (the Heritage Beneficiaries) (Energy Plan Policy Actions #3 and #7);

(2) Low electricity rates: The Heritage Contract should allow BC Hydro to: (a) maximize the value of the generating capabilities of the resources within BC Hydro's control and allow BC Hydro to minimize the cost of acquiring resources for Heritage Beneficiaries (Energy Plan Policy Actions #2 and #3); and

(b) provide the capability of the resources listed in Schedule A of the Terms of Reference, together with the related civil works and plant (collectively, the Heritage Resources), on the basis of their embedded cost (Energy Plan Policy Action #1).

BC Hydro's proposal is designed to meet these three objectives.

The Terms of Reference for this proceeding and the Energy Plan itself impose certain constraints on the way in which these objectives are to be served. In preparing this proposal, BC Hydro recognized the following specific constraints:

(1) BC Hydro is to be publicly owned and to be regulated by the Commission (Energy Plan Policy Actions #3 and #5)

(2) Independent power generation is to be encouraged (Energy Plan Policy Action #13);

(3) System operation will be implemented and new system resources will be developed in an environmentally responsible way (Energy Plan Policy Actions #9 and #20);

(4) The quantity of energy producible from the Heritage Resources is to be determined assuming average water conditions (Terms of Reference paragraph 2(d));

(5) Annual trade income in excess of $200 million will go to the government (Terms of Reference 9th recital);

(6) The Heritage Contract will be for an initial term of 10 years (Energy Plan Policy Action #1); and

(7) The Heritage Contract is to be between BC Hydro's generation and distribution lines of business (Terms of Reference, 7th recital).

In order to develop a proposal that would meet the three public policy objectives outlined above and within these constraints, BC Hydro adopted certain methodologies or principles that it believes are consistent with the Energy Plan. The principles are as follows:

(1) The Heritage Contract proposal ought to allocate to the Heritage Beneficiaries only those costs commensurate with the allocation of benefits;

(2) The Heritage Contract proposal should drive economically efficient decisions at the margin for supply, demand, and trade;

(3) The Heritage Contract proposal should serve its objectives simply and understandably as possible so that economic incentives will be clear to all participants; and

(4) To maximize system value, those operating the system and those buying and selling power from and for the system should have, to the greatest extent possible, unfettered communications.

BC Hydro also believes that the objective of light-handed regulation, and the encouragement of independent power producers elaborated in the Energy Plan, reflect a belief that where market mechanisms can work they should be permitted to do so to as great an extent as possible.

BC Hydro believes that this proposal serves each of these principles and the overall objectives of the Energy Plan.

Finally, BC Hydro believes that the Heritage Contract proposal can be implemented relatively easily by appropriate changes to Special Direction No. 8 to the Commission and Special Directive No. 4 to BC Hydro.

1.3 *Names, Titles and Addresses of Contacts for This Proposal*

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2 The Heritage Contract Proposal

2.1 *The Heritage Contract Proposal – What It Is*

2.1.1 Introduction

This section describes the key elements of the Heritage Contract proposal, and how they would be implemented if accepted by government. It takes a functional rather than organizational approach.

BC Hydro currently owns and operates the Heritage Resources, and sells their electricity output domestically through the coordinated operation of the generation, transmission, and distribution lines of business respectively (BCH Generation, BCH Transmission and BCH Distribution). Within BCH Transmission, Grid Operations (Grid Ops) operates the transmission system separately from the rest of BC Hydro. Powerex Corp (Powerex), a BC Hydro subsidiary, markets surplus BC Hydro electricity and engages in energy trade outside the province.

This organizational structure may not remain constant over the term of the Heritage Contract. For example, the function of Grid Ops will be taken over by a new independent corporation called British Columbia Transmission Corporation (BC Transmission Corp). The Heritage Contract proposal is intended to identify the functional approach that BC Hydro will maintain over the term of the Heritage Contract while allowing enough organizational flexibility to adapt to evolving conditions. The only exception to this approach occurs in the discussion of the Heritage Contract and the Heritage Contract itself (attached at Appendix C), which necessarily refers to the respective rights and obligations of BCH Generation and BCH Distribution to be consistent with the Energy Plan. Additionally Powerex is also specifically mentioned. Nevertheless, BC Hydro believes that the Heritage Contract proposal is sufficiently robust that it can be adapted to any alternative organizational structure that might develop over the term of the Heritage Contract.

2.1.2 Key Components of the Heritage Contract Proposal

The proposal contains three distinct components. First, it establishes a Heritage Contract between BCH Generation and BCH Distribution that defines the amount of electricity to be supplied by BCH Generation and the payment obligations of BCH Distribution. BCH Distribution's payment obligations under the Heritage Contract would factor into future BC Hydro revenue requirement processes.

Second, the proposal includes a method for defining the computation of net income from trading activities (Trade Income). This definition provides a clear distinction between purchase and sale transactions required for domestic purposes, and those made to support trading activities. Costs and revenues are allocated so as to properly identify only the latter as Trade Income. Along with this definition of Trade Income, BC Hydro then proposes a sharing formula to allocate a portion of Trade Income for the benefit of the Heritage Beneficiaries.

Finally, the proposal recommends establishing a deferral account designed to mitigate the volatility of BC Hydro's revenue requirements that may arise from its payment obligations under the Heritage Contract or from its receipt of Trade Income (Heritage Deferral Account). The Heritage Deferral Account would replace the existing Rate Stabilization Account (RSA).

Each of these components is interdependent, and changes to one will require changes to others. Thus, the components of the proposal ought to be understood as a comprehensive package. The key components are described in further detail below, and in Chapter 3 of this volume.

2.1.3 Heritage Contract

The Heritage Contract defines the electricity supply obligations of BCH Generation and the payment obligations of BCH Distribution in respect of the supplied electricity. Under this contract, the full capacity of the Heritage Resources will be provided to BCH Distribution on a priority basis. BCH Generation will arrange for the marketing of any surplus capability but at all times will ensure priority is given to the needs of BCH Distribution.

The Contract will allow energy deliveries to be shaped, within the capability of the Heritage Resources, in response to BCH Distribution's changing needs. The Heritage Contract will also allow coordination with other resources under BC Hydro's control. The capacity of the Heritage Resources may be utilised to facilitate domestic energy deliveries or to provide ancillary service requirements. These provisions will ensure that the Heritage Resources can be utilized to maximize overall benefits for the Heritage Beneficiaries over time.

The energy delivery obligation under the Heritage Contract is set at a maximum of 49,000 GWh per year (Heritage Energy). This amount is representative of the reliable capability of the Heritage Resources and has been derived by examining their historical and future expected use under average water conditions. Heritage Energy will be provided at the various points of interconnection of the Heritage Resources with the BC Hydro transmission grid or at points of interconnection with other utilities.

The actual capacity, ancillary service and energy supply from the Heritage Resources (collectively, the Heritage Electricity) will be provided on the basis of the embedded costs of the Heritage Resources, including actual fuel or purchase costs required to supply Heritage Electricity. More specifically, the Heritage Contract will establish a payment obligation based on actual costs (the Heritage Payment Obligation) for BCH Distribution comprised of the following components:

cost of energy: the cost of water fees and energy purchases (gas and electricity) required to supply Heritage Electricity;

operating costs: all costs of operating and maintaining the Heritage Resources, including an allocation of corporate costs;

asset related expenses: the costs of owning the Heritage Resources including depreciation, interest, finance charges and other asset related expenses;

generation related transmission assets: all costs or payments related to any generation-related transmission required by the Heritage Resources; and

return on equity: the appropriate return on equity, currently based on Special Direction #8, on investments in Heritage Resources.

less other revenues: any revenues received from other services provided from the Heritage Resources including revenues related to Skagit Valley Treaty obligations[1], revenues from provision of ancillary services to the transmission operator in respect of third party use of the transmission system, revenues from sales of surplus hydro, and other miscellaneous revenues.

To establish a context for future rate proceedings, BC Hydro has forecast that the cost of supplying the Heritage Electricity over the term of the Heritage Contract will average approximately $25.30 per MWh (Forecast Heritage Reference Price) over the period 2004/05 to 2013/14, under average water conditions, exclusive of trade income. The Forecast Heritage Reference Price is based on current forecasts and on the assumption that BCH Distribution will take all the Heritage Energy. If less energy is taken the per unit "price" will be lower by virtue of a reduced cost of energy (most of the other cost components being relatively insensitive to demand), and in any event will depend on the actual cost of Heritage Electricity. The derivation of the Forecast Heritage Reference Price and other assumptions used to derive it are summarized in section 3.7 below and follows the foregoing break-out of cost components.

Some of the Heritage Payment Obligation cost components are relatively certain (operating costs, for example), while others are highly volatile (cost of energy). Similarly, management has limited control over some costs (return on equity) and greater control over others. The Heritage Contract proposal can accommodate "performance based rate-making" (PBR) mechanisms for many of the more stable and controllable cost components of the Heritage Payment Obligation.

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[1] Under the Skagit Valley Treaty Seattle City Light is compensated in electricity for agreeing to forego the raising of the Ross Dam, which would have flooded in the Skagit Valley in S.W. British Columbia.

2.1.4 Trade Income Definition and Allocation

As part of this application, BC Hydro is proposing the use of a Trade Income definition in order to separate energy transactions required to support the domestic system and transactions for trade. This definition and the allocation issues it raises are described in detail below.

Under the Heritage Contract proposal, BC Hydro determines how the generation system will be operated to satisfy its domestic obligations and further determines how much surplus capability (import capability, capacity, etc.) is available for trade. Information on surplus capability is provided to those responsible for marketing (i.e. Powerex), who then make decisions on how, or if, they wish to use that capability for trading activities (buying and selling of energy). Information on expected inflows, expected resource availability, current and future market prices and other information is continuously shared to optimize system operation and maximize commercial return.

Under the definition of Trade Income, priority is given to domestic transactions. If BC Hydro needs to purchase electricity to satisfy its domestic obligations or to refill its reservoirs, imported energy will accrue to BC Hydro in accordance with its instructions. Similarly, if the domestic system has surplus hydro energy, BC Hydro will sell this energy to Powerex for re-sale in the market.

BC Hydro established Powerex to use the surplus capability of the system to engage in electricity trade, as well as buy electricity and gas for the purpose of facilitating sales to others. As Powerex may be involved in tons of thousands of transactions in the course of a year, transactions between Powerex and BC Hydro are not based on actual costs. Rather, transactions are based on a market index designed to reflect fair market value of the electricity provided.

Powerex pays BC Hydro for certain incremental costs associated with the use of Heritage Resources for trade, these being fuel costs and variable operating costs, and point-to-point transmission charges.

Therefore, Trade Income will include the revenues Powerex receives from sales to third parties and to BC Hydro reduced by its costs of purchasing electricity from third parties and BC Hydro, its costs for use of BC Hydro facilities (including transmission), its payments to other utilities for transmission and other services and its own operating costs.

Trade Income as defined in this proposal is forecast to be lower than trade income reported by BC Hydro in previous years. In previous years, revenue from sales of surplus hydro energy sold into the export market was included in income from trade. Under the proposed definition, surplus hydro energy would be sold to Powerex at the index price and the profit would directly reduce the Heritage Payment Obligation and thus effectively reduce BC Hydro's cost of energy. Thus Trade Income would reflect only the profit that Powerex could make relative to the market index price paid to BC Hydro. For this reason, Powerex is forecasting trade income in the range of $75-125 million in typical future years.

The Trade Income definition focuses on variable costs of generation, rather than the embedded costs of the generation system. This gives Powerex the right pricing incentive to maximize the commercial use of BC Hydro's facilities.

To provide a contribution from trade to the embedded costs of the generation assets, BC Hydro is proposing that Trade Income, up to $200 million per year, will accrue to the Heritage Beneficiaries. In accordance with the Terms of Reference, Trade Income above $200 million per year will accrue to government (through BC Hydro). In addition, to ensure customers are not adversely impacted by trading activities, BC Hydro will not pass on any trading losses to customers. These latter two provisions ensure that most profits from trade will accrue to Heritage Beneficiaries, while BC Hydro's shareholder will absorb the impact of extreme adverse outcomes, and receive the benefits of windfall profits. BC Hydro expects that these extraordinary circumstances to arise, if at all, from external events such as the California power crisis in 2000-2001.

2.1.5 Heritage Deferral Account

Several of the cost components of the Heritage Payment Obligation and components of Trade Income are highly volatile and could vary considerably from year-to-year and from forecast amounts. In particular, the cost of energy under the Heritage Contract could easily vary by plus or minus $300 million from forecast amounts. This is largely due to the variability of the water supply. There is a 70% probability that annual generation will fall within a range of plus or minus 5000 GWh from average conditions. Trade Income will be less volatile than under previous definitions, but could still fluctuate by plus or minus $50 million under typical conditions, and by greater amounts in extreme years.

To mitigate this annual volatility on BC Hydro's revenue requirement, BC Hydro is proposing a Heritage Deferral Account as a replacement for the RSA. In contrast to the existing RSA, the proposed Heritage Deferral Account would allow both positive and negative balances.

Initially, all differences between the Heritage Payment Obligation and forecast Heritage Payment Obligation used to calculate BC Hydro's revenue requirement would accrue to the Heritage Deferral Account. This can be adjusted to accommodate any possible PBR mechanisms in the future. The Heritage Deferral Account is described in more detail in section 3.5, below.

2.1.6 Summary of Heritage Contract Proposal

The Heritage Contract proposal contains a number of features to ensure that the full benefit of the Heritage Resources accrue to the Heritage Beneficiaries. The proposed payment mechanism ensures that BC Hydro revenue requirements will not increase as a direct result of the Heritage Contract proposal. The Energy Plan announced the end of BC Hydro's statutory rate freeze, effective April 1, 2003. Increases in costs since the current BC Hydro rates were established almost 10 years ago will likely make a rate adjustment necessary in 2004. However, such adjustment would be required with or without the Heritage Contract proposal.

The Heritage Electricity supply obligation ensures that the Heritage Beneficiaries will continue to have priority access to Heritage Resources and continue to benefit from the flexibility of those resources, allowing BC Hydro to shape overall supplies to meet overall demand. Because the contract calls for the flow-through of actual gas and electricity purchase costs required to satisfy Heritage Beneficiaries' use of Heritage Electricity, BCH Distribution is not obligated to take all of the Heritage Electricity. If energy is acquired from other sources, or if demands on the system are temporarily reduced, and, as a result, the need for Heritage Electricity is reduced, Heritage Beneficiaries will benefit from any reductions in the variable cost to supply demand. These features also allow the greatest flexibility for minimizing the cost of meeting future demand from a wide range of potential resources.

BC Hydro's Heritage Contract proposal differs in a number of material ways from the model used in Quebec (referred to in the Energy Plan). For example, Hydro Quebec's generating arm is required to provide a fixed quantity of energy at a fixed price. The advantage of this model is its simplicity. However, in the Hydro Quebec model the fixed quantity (165,000 MWh) is less than the average system capability. Because the Terms of Reference require the Heritage Contract to be based on average water, the direct application of the Hydro Quebec model to BC Hydro would impose greater costs on the Heritage Beneficiaries.

By contrast, BC Hydro's Heritage Contract proposal reflects the circumstances of BC Hydro's system by maximizing the value of the Heritage Resources and ensuring that those resources will continue to be utilized to provide maximum value to the Heritage Beneficiaries.

2.2 *The Heritage Contract Proposal – How It Would Work*

In this section BC Hydro describes how the Heritage Contract proposal would work, starting from the time of filing a revenue requirement application in 2004, through to the end of the Heritage Contract.

2.2.1 2004/05 Revenue Requirement Application

The Terms of Reference contemplate BC Hydro filing a revenue requirement application on or before March 31, 2004. BC Hydro will seek interim rate adjustments effective at that time. BC Hydro anticipates using a test period commencing in 2004/05.

A fundamental component of the revenue requirement will be a forecast of the Heritage Payment Obligation. That forecast will be different than set out in section 3.7 as it will be updated to reflect new information regarding forecast cost components of the Heritage Payment Obligation in the test period (such as cost of energy). The other significant component of the revenue requirement application that is related to the Heritage Contract will be a forecast of Trade Income (trade income is different than sales of surplus hydro energy, which is a component of the Heritage Payment Obligation – see section 3.3).

2.2.2 Revenue Requirements Forward From 2005/06

After the 2004/05 revenue requirement has been determined, BC Hydro anticipates that any changes in rates would be applied on a prorata basis, across all rate schedules. However, BC Hydro intends to file a rate design application that would lead to final rates reflecting an improved rate design by the end of 2004/05.

If at the end of a fiscal year the Heritage Payment Obligation was less than the forecast Heritage Payment Obligation approved in the revenue requirement, the difference would be credited to the Heritage Deferral Account. If the actual Heritage Payment Obligation was greater than the forecast Heritage Payment Obligation, the difference would be debited from the Heritage Deferral Account. Similarly any differences between forecast and actual Trade Income would accrue to the Heritage Deferral Account, subject to the $200 million ceiling and $0 floor.

Over time, the Heritage Deferral Account may accrue a large positive or negative balance. BC Hydro proposes that the account balance be cleared through rates, on application and with the approval of the Commission. This flexibility would allow BC Hydro and ratepayers to offset proposed rate increases or decreases that arise for other reasons. In each subsequent revenue requirement filing, BC Hydro will provide an updated forecast of the expected Heritage Payment Obligation for the test period.

3 Detailed Explanation Of Heritage Contract Proposal

3.1 *Optimization of System through Coordinated Operation*

BC Hydro provides a secure and reliable supply of electricity to its ratepayers through a combination of the Heritage Resources, electricity purchases from independent power producers (IPPs) (currently about 5700 GWh per year) and purchases from the wholesale electricity market (about 2500 GWh per year based on planning criteria).

BC Hydro's operation of the generating facilities under its control are guided by the following objectives:

- ensuring the safety of lives and property
- meeting current and future electricity demand
- maximizing the value of generating resources

Subject to the foregoing, and using the three sources of supply, BC Hydro optimizes its system to serve ratepayers in the least cost manner, while at the same time maximizing electricity trade revenues. In general terms, BC Hydro purchases electricity to serve domestic demand or when it is economic to displace generation from the Heritage Resources or certain (dispatchable) IPPs. When there is surplus hydro energy generation from the BC Hydro system, BC Hydro makes that surplus available to Powerex for re-sale outside BC to offset the cost of serving domestic demand. In addition, BC Hydro makes available to Powerex any surplus system capability to earn Trade Income.

These objectives and the conflicting operating parameters they suggest must be reconciled with the myriad treaties, statutes, regulations, licenses and orders of regulatory bodies to which BC Hydro's operations are subject.

Additionally, BC Hydro must operate the integrated system in light of its interconnections with the electrical systems of Alberta and the United States. In so doing, BC Hydro is called upon to determine on an hourly basis whether to generate enough power to meet domestic load requirements, or to import power and thereby store its inflows in reservoirs for future use. It makes these decisions by considering external energy markets; domestic load; flow requirements (for hydro generation); air shed and natural gas supply conditions (for thermal generation); available transmission capacity; and its obligations to operate in a manner that will not adversely affect the interconnected electrical systems.

Further, decisions regarding the operation of any particular facility both constrain and are constrained by the operation of other facilities. Often the objectives and constraints suggest conflicting courses of action. For example, a generator may be run even if it is not the lowest cost generator at the particular time because of minimum flow requirements imposed to protect fish or their habitat. Operation of an upstream project may require operation of a downstream project to avoid spill. These constraints change on a day-by-day and hour-by-hour basis as a result of unexpected precipitation and other natural phenomena. This interdependence of the Heritage Resources is an essential characteristic of the system.

Due in large part to the complexity of operating the system, BC Hydro proposes in this application to maintain the current coordinated working relationships within BC Hydro as a means of optimizing system value. In particular, in order to allow the system to be optimized today and in the future, the Heritage Contract proposal needs to be flexible enough to ensure that a coordinated approach to meeting overall domestic demand can continue. From an operating perspective, there needs to be coordinated dispatch of the Heritage Resources, IPP purchases, and market purchases so that the least opportunity cost supplies are used first. For example, the Heritage Contract should not impose obligations to "force" uneconomic dispatch of any Heritage Resource when more economic supplies from IPPs or the market may be available. From a long-term resource acquisition perspective, and to achieve overall least cost (in a manner consistent with the Energy Plan), BC Hydro's decisions on new resource acquisitions need to continue to take into consideration the cost to produce electricity and its impact on Trade Income. Again, this requires close working relationships within BC Hydro (to the exclusion of Grid Ops). Close working relationships will minimize the already complex decision-making, and ensure that the value of the Heritage Resources is optimally utilized to provide greatest overall value.

The foregoing also explains the manner in which BC Hydro deals with its trading arm, Powerex. Although Powerex makes no decisions as to when and how BC Hydro's system is operated, it is closely involved in the development of these decisions. For example, Powerex advises on the development of market opportunities. Similarly, BC Hydro keeps Powerex closely apprised of the ever-changing system capabilities and opportunity costs of stored water. This close working relationship minimizes transaction costs, facilitates timely decision-making, and is an essential ingredient to maximizing the overall value of BC Hydro's system. In this application, BC Hydro proposes that this essential cornerstone of system optimization be continued through the term of the Heritage Contract.

These close working relationships are in distinct contrast to the operational arms-length relationship between Grid Ops and the rest of BC Hydro, and Powerex, that has been in place since 1996 and that will be further effected when BC Transmission Corp is created.

3.2 *Heritage Electricity Supply Obligation*

3.2.1 Heritage Energy Component of Heritage Electricity

The Energy Plan indicates that the quantity of energy included in the Heritage Contract will be based on the production of the Heritage Resources under average water conditions. To develop the quantity of energy for the Heritage Contract, BC Hydro has examined the historical average energy from the Heritage Resources and simulation studies of expected future generation from these resources. Based on this analysis, BC Hydro is recommending that the Heritage Contract provide for a maximum energy supply obligation, subject to force majeure, of 49,000 GWh per year (the Heritage Energy).

Table 1 provides the capability of each of the Heritage Resources based on these analyses. That table shows the capacity and energy capability of each resource (as documented in the BC Hydro report *Making the Connection*) and the actual generation averaged over the period from 1985[2] through 2002. It also provides an estimate of future generation capability based on the range of historical inflows that occurred over the period from October 1940 through September 2000.

Historical information ignores any changes to project facilities and operating criteria over the period of record. Simulation studies can adjust for existing facilities and operating criteria, but may overestimate average energy generation due to smoothing of real-life volatility and market conditions. Simulation studies also do not capture the energy reductions due to unusual events that sometimes occur. As a result, the estimate of future hydro generation is about 920 GWh higher than the historical average generation. This increase is largely attributable to changes in project characteristics and operating criteria that have occurred since 1985, and differences in flows over the periods of record. Significant changes include the installation of Seven Mile Unit 4, Resource Smart project improvements at Mica, Revelstoke, Kootenay Canal, Stave Falls and other projects, and changes in operating criteria at Cheakamus, Seven Mile and other projects. In addition, the historic generation reflects the impacts of force majeure events such as the sinkhole at the WAC Bennett Dam and the tunnel breach at Wahleach.

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[2] 1985 is the first year that all Heritage Resources were fully in service (with the exception of Fort Nelson).

The data shown in Table 1 for Kootenay Canal also warrants further explanation. The historical data for the period from 1985 through 2002 and similar data from *Making the Connection* are based on metered generation at Kootenay Canal. The computer simulation data incorporates a full simulation of the Canal Plant Agreement. In this simulation, the average capability for the combined Pend d'Oreille and Kootenay River system is determined and the entitlements under the Canal Plant Agreement are deducted. The net generation available to BC Hydro from this total system operation is then attributed to Kootenay Canal. Because of system optimization benefits that BC Hydro receives under the Canal Plant Agreement, this value is slightly higher than actual Kootenay Canal generation. Similarly, BC Hydro expects to receive a small average energy benefit from the Keenleyside Entitlement Agreement.

The capability of thermal resources is not impacted by stream flow conditions; rather, it is primarily related to the installed capacity, the availability of fuel and the requirements for maintenance and forced outages. However, the actual dispatch of thermal resources is significantly impacted by stream flow conditions and by fluctuations in electricity and fuel prices. While the theoretical capability of the thermal Heritage Resources is estimated at 6280 GWh (excluding Fort Nelson), the expected generation in average water conditions is only about 2400 GWh (slightly higher than historical thermal usage, excluding Fort Nelson). In many market conditions, electricity purchases may displace actual generation at thermal plants. In addition, only a portion of the output of the Fort Nelson generating station directly benefits the Heritage Beneficiaries. The remainder of the output is available for electricity trade with Alberta, and thereby indirectly benefits Heritage Beneficiaries through the allocation of Trade Income.

Based on this analysis, BC Hydro recommends that a maximum supply obligation of 49,000 GWh per year be adopted for the Heritage Contract. This obligation would be subject to force majeure events that severely impact the system capability.

	MtC Capacity MW	MtC Energy GW.h	Actual 1985-2002 GW.h	Simulation 1940-2000 GW.h
Aberfeldie *	5	34	33	
Alouette	9	30	36	53
Ash	27	193	184	193
Bridge River	466	2479	2527	2666
Buntzen	73	183	170	126
Cheakamus	157	750	714	638
Clowhom	33	121	122	126
Duncan	0	0	0	0
Elko *	12	73	76	
Falls River *	7	45	47	
G.M. Shrum	2730	13225	13798	13070
Hugh Keenleyside	0	0	0	20
John Hart	126	776	762	823
Jordan River	170	242	241	261
Kootenay Canal	570	3153	3162	3270
Ladore	47	229	229	280
LaJoie	25	162	161	172
Mica	1805	7202	7226	7450
Peace Canyon	694	3111	3440	3375
Puntledge	24	156	151	159
Revelstoke	1980	7817	8094	8400
Ruskin	105	339	338	374
Seton	48	325	333	321
Seven Mile	594	3102	2913	3523
Shuswap *	6	37	37	
Spillimacheen *	4	20	20	
Stave Falls	90	276	264	362
Strathcona	64	222	219	246
Wahleach	63	245	253	282
Walter Hardman *	8	46	44	
Whatshan	54	121	123	124
Other - includes *				266
Resource Smart (not simulated)				55
Sub-total	9996	44714	45715	46635
Burrard	913		1771	
Prince Rupert	46		19	
Average Thermal or Import (net of expected surplus sales)				2335
Sub-total	959	0	1790	0
Grand Total	10954		47505	48970
Fort Nelson (domestic supply)	45		N.A.	155
Grand Total	10999			49125

Note: "MtC" - BC Hydro Document "Making the Connection"
"N.A." - Not applicable

Table 1: Heritage Resource Average Capability Comparison

3.2.2 Capacity Component of Heritage Electricity

Bundled service provision: Under the Heritage Contract proposal, Heritage Beneficiaries will get the benefit of first priority to the full capacity of the Heritage Resources. BC Hydro is proposing to provide a bundled package of electricity services to the Heritage Contract Beneficiaries. The continued provision of bundled service enables BC Hydro to minimize the cost of future resource additions. It also serves the principle of simplicity and ease of understanding.

Shaping and scheduling flexibility: One of the most valuable aspects of the hydro Heritage Resources is the large reservoir storage capacity, which permits energy generation at times that it is most valuable. BC Hydro uses this reservoir storage to shape generation to minimize the cost of serving domestic demand and to optimize income from electricity trade.

Over the course of the term of the Heritage Contract BC Hydro expects that domestic demand will get "peakier", and believes that most new resources will come on-line with relatively little ability to be shaped. These factors will increase the capacity demands on the Heritage Resources and in particular those hydroelectric projects with large storage capacity, but in an unpredictable manner. Maximizing the value of the Heritage Resources requires that BC Hydro shape and schedule deliveries of energy in response to actual demand of the Heritage Beneficiaries on an hourly basis, as is the current practice.

3.2.3 Ancillary Service Component of Heritage Electricity

As part of supplying the 49,000 GWh per year of Heritage Energy and providing priority access to the capacity Heritage Resources, BC Hydro will operate the Heritage Resources to supply ancillary services. Ancillary services are those functions necessary to support the transmission of electrical power from generation resources to loads while maintaining system reliability. To meet current domestic demand, BC Hydro self-supplies ancillary services from the Heritage Resources. It also provides ancillary services in support of third party use of the BC Hydro transmission grid.

BC Hydro's Wholesale Transmission Service Tariff provides for the sale of seven different ancillary services, based on the embedded cost of providing these services. With the exception of System Control and Dispatch, ancillary services are an encumbrance on generation capability. In essence, some generation capability must be used to provide ancillary services.

To minimize the cost of ancillary services to Heritage Beneficiaries, BC Hydro proposes to continue to self-supply ancillary services, even after BC Transmission Corp begins to operate the BC Hydro transmission grid. In essence, the capacity available under the Heritage Contract can be used to either deliver energy to meet customer demand or to satisfy its ancillary service obligations. BC Hydro will continue to provide ancillary services in support of third party wheeling as required by its current tariffs or as may be required under future arrangements with BC Transmission Corp.

3.2.4 Other Rights and Obligations

In accordance with the Terms of Reference, the Heritage Contract must allow for rights and obligations under the Columbia River Treaty, the Skagit Valley Treaty, the Canal Plant Agreement and the Keenleyside Entitlement Agreement. The energy capabilities derived from the Columbia River projects have accounted for the rights and obligations related to the Columbia River Treaty, the Kootenay Canal Agreement and the Keenleyside Entitlement Agreement.

The Skagit Valley Treaty requires BC Hydro to deliver about 310 GWh of energy annually to Seattle City Light. Including losses, this results in an annual generation requirement related to the Skagit Valley Treaty of approximately 340 GWh. Therefore, the Skagit Valley Treaty obligation will be served out of the 49,000 GWh Heritage Energy supply obligation, resulting in approximately 48,660 GWh being available for the Heritage Beneficiaries under the Heritage Contract proposal.

Currently, the Power for Jobs agreements and Replacement Electricity Supply Agreement between the Province and Alcan do not have a significant impact on the Heritage Energy supply obligations. However, if Alcan develops a new smelter that triggers the Replacement Electricity Supply Agreement, the Province's obligation to supply that smelter may reduce the energy available to other Heritage Beneficiaries.

3.2.5 Point of Delivery and Point of Metering

In keeping with the concept of bundled service, BC Hydro proposes that the nominal electricity delivery point be at the interconnection of BC Hydro's system and the parts of BC Hydro's system that will be controlled and operated by BC Transmission Corp.

The proposed point of metering is at the generator output terminals. That is, the Heritage Energy is inclusive of all line losses from that point, including losses that may be incurred on the generation-related transmission system. This is consistent with past practice and is also consistent with the derivation of the average energy capability of the Heritage Resources, in which historical information and system studies are based on capabilities measured at the generator.

3.3 *Trade Income*

3.3.1 Deriving Benefits from Accessing External Markets

In addition to providing low-cost electricity under the Heritage Contract, BC Hydro's Heritage Resources provide value through the sale of surplus electricity and through Powerex's trading activities. Trade activity by Powerex and supported by the Heritage Resources provides value in a number of ways including the following:

BC Hydro takes advantage of Powerex's access to markets throughout the Western Interconnection[3], to optimize the commercial return of the BC Hydro system. Powerex buys electricity from the market for re-sale to BC Hydro to meet domestic demand when as determined by BC Hydro the cost of doing so (including opportunity cost) is less than the cost of BC Hydro generating and supplying domestic demand. Conversely, at times when BC Hydro has surplus capability it sells electricity to Powerex for re-sale on the market. Transactions between BC Hydro and Powerex are accounted for on the basis indexed-based prices, described below.

Natural gas has become a more important part of BC Hydro's supply portfolio with the addition of thermal generation at Elk Falls and Fort Nelson, in addition to Burrard Thermal. Powerex acquires gas through a mix of spot and forward transactions and then supplies it to BC Hydro in specified quantities at designated hubs in return for an index-based price.

Through Powerex, BC Hydro also has the option of hedging its costs or revenues, reducing its exposure to volatile commodity gas and power prices for domestic supply.

3.3.2 Definition of Trade Income

BC Hydro proposes that Trade Income for any period be calculated according to the following formula:

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[3] The Western Interconnection is the geographical area in the Western part of North America in which the electric grid is operated synchronously. It includes British Columbia and Alberta, and stretches through the western United States into Mexico.

Powerex revenue from sales to BC Hydro and third parties
Less Powerex cost of energy from BC Hydro and third parties
Less Powerex cost of transmission for trade
Less Powerex transaction costs
Less incremental BC Hydro costs (fuel costs and variable operating costs)
Less operating costs of Powerex

= Trade Income

Sales revenue is derived from Powerex's sales of electricity, gas, and ancillary services to BC Hydro and to third parties. Sales to BC Hydro would include electricity and gas necessary to meet domestic demand. Similarly, cost of energy would be derived from Powerex's purchases of power, gas and ancillary services from BC Hydro and from third parties. Purchases from BC Hydro would include surplus hydro energy during high water years, and gas that is surplus to BC Hydro's domestic demand. Other energy-related products, such as Green Tags and Greenhouse Gas Emission Reduction Credits, would be included in the revenue and cost figures as transactions occur.

In most cases, sales revenue and cost of energy would be based on actual transaction prices with third parties. However, net imports into and net exports from the BC Hydro control area, as well as generation from BC Hydro thermal plants, require special treatment because of allocation and pricing difficulties (see discussion below).

The cost of Powerex's transmission for trade would include an allocation of BC Hydro's cost of purchases of point-to-point transmission within BC for export and some import transactions. It would not include point-to-point transmission to meet BC Hydro's Skagit Valley Treaty commitment, nor would it include point-to-point transmission for the Canadian Entitlement, when that power is simultaneously imported into and exported from the BC Hydro system at the same interconnection point.[4]

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[4] The Canadian Entitlement is Canada's share of the energy and capacity benefits that arise under the Columbia River Treaty. Canada assigned that share to British Columbia under the terms of a 1963 agreement.

The cost of transmission would also include purchases of transmission, ancillary and loss services outside of BC necessary to meet Powerex's delivery commitments outside of BC. It would not include US transmission costs required to meet BC Hydro's Skagit Valley Treaty commitments, or other BC Hydro commitments.

The incremental BC Hydro costs associated with Powerex's trade activity include fuel costs and variable operating costs.

3.3.3 Allocation of Trade Income

BC Hydro proposes that all Trade Income accrue to Heritage Beneficiaries, subject to the $200 million ceiling set out in the Terms of Reference, as an offset against BC Hydro's revenue requirement. This maximizes the contribution of trade activity to the fixed costs of the system. In addition, BC Hydro believes that this allocation allows it to maximize the value of BC Hydro's system in a manner that is consistent with the Terms of Reference and that does not create operational and managerial conflicts for BC Hydro. Other divisions of Trade Income between government and Heritage Beneficiaries could lead to conflicting courses of action where the optimal solution is not clear (operate for government or Heritage Beneficiaries' benefit). With the definition of Trade Income in this proposal, the potential to approach the $200 million ceiling is remote, and therefore the allocation over $200 million is very unlikely to affect trading behaviour in a material way. To further support this conclusion, BC Hydro will match purchases and sales in the same year in the calculation of Trade Income.

The $0 floor simply continues existing BC Hydro practice of holding ratepayers harmless from its unregulated activities, or the unregulated activities of its subsidiaries.

3.3.4 Allocation Issues

In order to define Trade Income using the methodology described in this section, it is necessary to allocate certain energy activities, such as imports, exports, and thermal generation, to either domestic or trade accounts. To that end, BC Hydro proposes the allocation methodology described in this section.

Three key principles underlie the allocation methodology:

(1) BC Hydro has first priority access to Powerex's imports and exports and to thermal generation to meet domestic supply. This means that domestic customers would generally receive the lowest cost imports, the highest value exports and first access to BC Hydro's thermal generation to meet domestic load. If these capabilities are not required for domestic supply in a particular time period, Powerex could access surplus capability to engage in trade activity at a later date.

(2) The allocation decision is made at the time of the decision to import, export, or generate for a particular day or time, based on the best information available to decision-makers at that time.

(3) Utilizing surplus capability to acquire electricity with the expectation of future export sales is the sole responsibility of Powerex.

The proposed allocation methodology depends on determining the value of power being imported into the BC Hydro control area. Because of the complexity of the Powerex portfolio, which includes tens of thousands of purchases and sales each year for hourly, daily, monthly and longer term blocks at many different delivery points throughout the Western Interconnection, it is not possible to allocate purchases based on actual transaction prices in any meaningful way. As a workable and reasonably accurate alternative, BC Hydro proposes that imports into the BC Hydro control area be valued at the Mid-Columbia index price (as was done in BC Hydro's Real Time Pricing tariff) plus the cost of transmission between Mid-Columbia and the BC border.

Prior to the delivery day, BC Hydro would specify a threshold price below which it would be willing to import power for domestic supply. If the index price adjusted for transmission is below the threshold level, imports would be allocated to domestic supply. Powerex would be paid the index-based price. The risk and reward associated with purchasing power to meet this price would accrue to Trade Income. If the index price adjusted for transmission is above the threshold level, any imports would be allocated to Powerex to enable additional sales at a later date.

The same methodology would apply to gas-fired generation, with BC Hydro providing a threshold price for power generated from its thermal plants below which it would be willing to generate power for domestic use.

Exports would be treated in a similar manner, with BC Hydro providing Powerex with a threshold sell price below which it would not be willing to make surplus power sales. In the case of exports from the BC Hydro control area, the power would be valued at the Mid-Columbia index price less the cost of transmission between Mid-Columbia and the BC border.

3.3.5 Trade Income Forecast

The Trade Income forecast of $75 to $125 million noted in subsection 2.1.4 above may appear relatively low. There are three explanations for this.

First, Trade Income is defined more narrowly than it has been historically. Under the proposed definition most gross profit from sales of surplus hydro energy would not accrue to Trade Income. Instead, it would be allocated directly against the Heritage Payment Obligation. This means the volatility of BC Hydro's hydro inflows, and the resulting income uncertainty, would have a relatively small impact on Trade Income.

Second, unlike previous definitions of the contribution of trade, Trade Income includes BC Hydro point-to-point transmission costs. This allocation of fixed transmission as variable costs allocated on a per transaction basis could distort the economic optimization of BC Hydro generation for trade. Wholesale Transmission Service tariff mechanisms do exist to discount transmission below the full price to mitigate this impact. Prior to the establishment of a west-wide regional transmission organization and the introduction of efficient transmission pricing, it is expected that the BC Transmission Corp will discount transmission rates to encourage electricity trade transactions by BC Hydro, IPPs and third parties.

Third, market prices have normalized following the high-price period of 2000 and 2001. The Trade Income forecast is based on prices within a historically normal range going forward.

3.4 *Regulatory Framework for Trading Function*

3.4.1 Maintenance of an Efficient Trading Operation

The benefit of the Heritage Resources will be passed on to the Heritage Beneficiaries in kind through the provision of low cost energy and financially through the income earned from trade. To maximize the potential for this latter financial benefit from the Heritage Resources it is important to maintain an efficient trading operation.

BC Hydro does not engage directly in any material trading activity. Instead, it sells surplus hydro energy to Powerex at the BC border and Powerex assumes responsibility for marketing this power in Alberta or the U.S. Powerex also buys and sells electricity in the U.S. and Alberta. This latter activity can enhance the value of BC Hydro's surplus. All of Powerex's revenues are consolidated with those of BC Hydro for ratemaking purposes under Special Direction No.8. Therefore, under the current regulatory structure, net income from all of Powerex's activity reduces the revenue requirement that must be recovered from ratepayers.

3.4.2 Regulation of the Trading Function

An efficient trading operation requires the flexibility to adapt to changing market rules and circumstances; an ability to make timely decisions; and a focus on market conditions. Each of these factors suggests that regulation of the trading function should be minimal. Moreover, trading success is best obtained by an alignment of interests amongst the marketing organization, its employees carrying out the trades, and the beneficiaries of successful trading. If the interests are aligned, pre- or post-activity regulation should be unnecessary. Accordingly the presence of unnecessary regulation would increase costs and hamper necessary flexibility.

Over the years, the consolidation of BC Hydro and Powerex revenues and RSA have had the effect of aligning the interests of Powerex, BC Hydro and its customers. The Heritage Contract proposal will ensure that this alignment of interests continues by making BC Hydro's ratepayers the beneficiaries of Trade Income (up to $200 million). In all foreseeable conditions, the more Trade Income is earned, the less the revenue requirement. In consequence, there are no diverging interests that a regulator need be called upon to balance.

Because Trade Income affects the interests of ratepayers, the Commission will continue to be kept apprised of trade activities. This requirement is essentially the same as that which exists under the RSA. Accordingly, BC Hydro recommends a regulatory framework of the same type that exists today. Quarterly trade activity reports should be filed with the Commission to keep it apprised of Powerex's approach and results. Regulatory intervention should only be considered if a specific concern is identified in connection with the trading activity. Even then, tailored solutions as opposed to general regulation should be sought to avoid the negative consequences on performance likely to result from the latter.

3.5 *Risk Management and the Heritage Deferral Account*

As specified in the Energy Plan, the Heritage Contract is to have a minimum ten-year term. During this term, actual costs to supply the Heritage Electricity will vary from the expected costs, sometimes significantly. Fixing the Heritage Payment Obligation for ten years would require that all risks, both financial and operational, be reflected in the price in order to compensate BC Hydro for assuming such risks. As this would significantly increase the pricing, BC Hydro proposes instead to set its revenue requirement on the basis of the forecast Heritage Payment Obligation. To mitigate annual volatility of its revenue requirement, BC Hydro proposes that the Heritage Deferral Account replace the existing RSA. Thus BC Hydro's proposal is to allow for the lowest long-term cost to supply the Heritage Contract.

3.5.1 Variability in the Heritage Payment Obligation

As described above in section 2.1, the Heritage Payment Obligation is proposed to be the actual cost to supply Heritage Electricity. This avoids the need to quantify and monetize in advance the inherent financial and operational risks associated with supplying Heritage Electricity for an extended period of time, and thereby helps keep the overall average payment low.

BC Hydro's proposal is for the forecast Heritage Payment Obligation to be approved as part of BC Hydro's overall revenue requirement. This would allow for the updating of cost and energy usage information so that the cost of Heritage Resources collected in customer rates reflects expected conditions.

On an annual basis, while the majority of the cost components (such as operating and maintenance costs) are relatively stable, several of the cost components of the Heritage Payment Obligation are quite volatile and could vary significantly from forecast amounts. Key drivers of volatility are variability in water inflows, gas commodity prices, market electricity prices and interest rates. All these drivers are outside of BC Hydro's control, although BC Hydro mitigates the adverse impacts of these drivers as much as prudently possible.

Demand for Heritage Energy: The cost of energy component in a forecast of the Heritage Payment Obligation would be based on expected domestic demand derived from planning simulation studies that take into account BC Hydro's forecasts of its own generation, IPP supply and purchases from the electricity market. Variances from any of these forecasted sources will cause a variance in demand on Heritage Energy. Over time, the shape of the demand for Heritage Energy will change as the load profile for BC Hydro changes and new purchases from IPPs are made. These changes will affect the cost of energy and the amount of revenue from surplus hydroelectric sales.

Hydroelectric generation: The cost of energy component in a forecast of the Heritage Payment Obligation would assume expected hydroelectric generation. However, due to variations in water inflows, actual hydroelectric generation will vary by +/-5000 GWh per year compared to the average hydroelectric energy capability (approximately 46,600 GWh). This volatility represents approximately one standard deviation from the mean or, in other words, a 70% probability that hydro generation will fall within this range. In fact, hydro generation has varied from a minimum of 37,600 GWh in 1995 to a maximum of 54,600 GWh in 1996.

High water inflows allow for a greater proportion of energy demand to be met using low-cost hydro generation instead of higher-priced thermal generation or energy purchases, thereby reducing the cost of energy. The unit cost of thermal generation or energy purchases is significantly greater than the unit cost of hydro generation. Consequently, assuming reservoir levels are sufficient, hydro generation will invariably be the preferred choice.

High inflows can also lead to surplus hydro energy that can be sold at a profit and which would result in higher than forecast surplus hydro energy sales. Conversely, low water inflows means that less Heritage Energy could be supplied from low cost hydroelectric generation and more energy would be supplied from thermal generation or energy purchases. This would result in a higher cost of energy than forecast. Assuming a market cost of energy of $60 per MWh, a +/-5000 GWh per year variation in hydroelectric generation can result in a +/-$300 million variation in cost of energy.

Gas and electricity market prices: Gas and electricity prices in external markets have a significant impact on the cost of energy and on Trade Income. Market prices that are relevant to the Heritage Contract are strongly influenced by market conditions in the Pacific Northwest and in California, where the majority of BC Hydro's electricity trade transactions occur. Factors such as water inflow levels, gas prices, unit outages and weather conditions in the Pacific Northwest and California all influence market prices.

Assuming average hydroelectric generation, a +/-$20 per MWh variation in electricity market prices or gas generation costs can cause a variance in the cost of energy of +/-$40 million. However, when combined with the variability in hydro generation, the impact of gas and market price variability is even more significant.

Forced outages: The hydroelectric generation component of the Heritage Electricity supply obligation takes into account an average amount of forced outages. As assets age, there is an increased probability of a need for more frequent and longer outages to repair or replace equipment. Also, unusual events can occur such as the sinkhole event at the WAC Bennett Dam. No explicit reduction in energy capability in Heritage Electricity is proposed in advance to account for such non-permanent events. Instead, it is proposed that the variance in energy capability, as impacted by unforeseen outage requirements, be reflected through changes in the Heritage Payment Obligation. For example, if there is a plant outage resulting in reduced hydroelectric generation, the cost of energy will be higher because BC Hydro will need to generate additional energy from thermal resources or purchase additional market supplies.

Finance charges: Changes in interest and foreign exchange rates can have a significant impact on finance charges. BC Hydro uses debt management strategies to minimize the impact of interest rate and foreign exchange fluctuations. However, these fluctuations can still exert significant influence on finance charges, which could easily vary from forecasted amounts by +/-$25 million per year or more for the Heritage Contract.

3.5.2 Using the Heritage Deferral Account to Account for Initial Conditions

BC Hydro currently expects reservoir levels to be below average at the start of the Heritage Contract in April 1, 2004. BC Hydro does not propose to make an explicit adjustment for reservoir levels, but instead proposes to rely on the Heritage Deferral Account to capture the cost impacts of the actual initial reservoir conditions. For example, if the initial reservoir levels at the start of the Heritage Contract were low, there would be a greater likelihood that the Heritage Payment Obligation would be higher than if the initial water conditions were more favourable. This is an appropriate mechanism to account for initial water conditions because the Heritage Contract proposal reflects a continuation of the benefits that the Heritage Beneficiaries currently enjoy from the BC Hydro system. Appendix E provides an example that shows how the Heritage Deferral Account might be employed.

3.5.3 Amending the Heritage Contract

Over the term of the Heritage Contract events could occur that could materially change the average energy capability of the Heritage Resources or BC Hydro's cost structure. In such circumstances, BC Hydro proposes that the Heritage Contract be amended, with Commission approval.

The criteria for triggering an amendment to the Heritage Contract would be a material one-time event or change in circumstance that permanently results in a change to the capability of the Heritage Resources or BC Hydro's cost structure. Examples are Water Use Planning[5], a change in allowed use of Burrard Thermal, or retirement of uneconomic Heritage Resources.

3.5.4 Future BC Hydro Generation Projects

Resource Smart projects increase the capability of the Heritage Resources through physical and operational modifications to existing facilities. BC Hydro proposes that Commission approval of these projects would allow their associated costs (such as depreciation or operating costs, for example) to be recovered in the Heritage Payment

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[5] Pursuant to Water Use Plan Guidelines issued by the provincial government in 1998, BC Hydro has committed to develop Water Use Plans for its hydroelectric generating facilities that would define detailed operating parameters for each of those facilities.

Obligation. Thus the benefits of such projects would accrue to the Heritage Beneficiaries through an increase in Heritage Energy, or by a reduced cost of energy.

Should BC Hydro develop and construct significant new non-Resource Smart generation capability at the location of the Heritage Resources but outside the Heritage Contract (with government approval), BC Hydro would seek the Commission's approval of the appropriate methodology to allocate the incremental costs and benefits associated with these non-Heritage Resources. Potential projects that BC Hydro may choose to develop outside the Heritage Contract include Units 5 and 6 at Revelstoke and Mica Generating stations.

3.5.5 Recognizing Deferral Account Balances in Rates

As mentioned above, the Heritage Deferral Account will help to smooth rates by capturing variances in the cost components of the Heritage Payment Obligation. That said, BC Hydro may be applying for other deferral account mechanisms in conjunction with its revenue requirement filing in March 2004. Collectively, these mechanisms would form a suite of deferral accounts, the balances of which would be considered with each other.

It is appropriate to consider the aggregate balance of all deferral accounts - in conjunction with prevailing rate levels and forecast rate changes - when deciding how (and if) to reflect any deferral account balances in rates for a given period. As such, BC Hydro is suggesting that the Heritage Deferral Account described in this proposal should not automatically "clear" its balances against any forecast Heritage Payment Obligation (which is just one input to the overall BC Hydro revenue requirement). Instead, all deferral account balances should be considered by the Commission when setting the rates of BC Hydro in respect of the Heritage Beneficiaries.

Consequently, BC Hydro suggests that it is not appropriate to propose at this time any defined limits on the balances that may accrue in the Heritage Deferral Account. Instead, BC Hydro will bring forward, at the time of its revenue requirement application, a comprehensive proposal it believes to be appropriate for the disposition of aggregate deferral account balances. Such a proposal could range from firm caps with defined amortization periods to an entirely "application-based" approach (where the utility, ratepayers, or the Commission may apply to bring deferral balances into rates).

As a final comment on the proposed Heritage Deferral Account, BC Hydro observes that the adoption of its proposal is inconsistent with preserving the RSA. At this time, BC Hydro does not expect that the RSA will be carrying a balance at the time the Heritage Contract comes into force. However, should the RSA be in a non-zero position at the time of its replacement, BC Hydro suggests that the balance should be transferred to the Heritage Deferral Account, to be reflected in BC Hydro's rates at the Commission's discretion.

3.6 *Renewal Provisions*

This Heritage Contract is being developed in response to the Energy Plan. The 10 year Heritage Contract term in the Energy Plan suggests that it is appropriate to review Provincial energy policy about every 10 years.

The nature of future policy changes is impossible to forecast at this time. However, it is appropriate for the Heritage Contract proposal to allow for sufficient notice to ensure an orderly transition to any new policy.

BC Hydro therefore recommends that the Heritage Contract proposal remain in effect until four years after any government policy direction calling for changes to the Heritage Contract.

3.7 *Forecast Heritage Payment Obligation (2004/05 to 2013/14)*

3.7.1 Introduction

BC Hydro will be responsible for the management and operation of the Heritage Resources, and delivery of the Heritage Electricity. Within BC Hydro, that responsibility currently resides with BCH Generation. BC Hydro is also, and will continue to be, obliged to serve all its ratepayers, and deliver to them their actual electricity demand. The cost of the former will not coincide with the latter, but will be a component of it. Thus, a forecast Heritage Payment Obligation will be a component of BC Hydro's revenue requirement through the term of the Heritage Contract. With each revenue requirement application, the forecast Heritage Payment Obligation will be updated.

The remainder of this section sets out, for illustrative purposes, a calculation of the Heritage Payment Obligation over the 10 year term of the Heritage Contract. It is based on current forecasts in 2003 dollars (except where otherwise stated) and average water inflows. It also assumes that at all times the Heritage Beneficiaries take all the Heritage Energy. (Because the Heritage Payment Obligation has a variable cost component – cost of energy – an assumed lower demand would have led to a lower per unit price).

The information contained in this section was also used to calculate the Forecast Heritage Reference Price, noted in section 2.1. That price, $25.30 per MWh, is the quotient of the average forecast Heritage Payment Obligation calculated from Tables 2 and 3 below (2005 to 2014), and 48,660 GWh (49,000 GWh less 340 GWh on account of Skagit Valley Treaty obligations).

3.7.2 Forecast Heritage Payment Obligation Fiscal 2005 - 2007

Table 2 sets out the forecast Heritage Payment Obligation for fiscal 2005 through 2007 (that is, the fiscal years ending March 31, 2005 – 2007), and its constituent components. The fiscal 2004 figures are provided for comparative purposes only. More detail on each component is found in Appendix F.

	Reference	Heritage Contract		
	2004	2005	2006	2007
Heritage Contract Costs				
Cost of Energy	$441	$441	$430	$434
Operating Costs	162	158	168	166
Asset Related Expenses	380	370	389	392
GRTA Expenses	43	43	43	43
Total Heritage Contract Costs	**1,026**	**1,012**	**1,030**	**1,035**
Less Other Revenues				
Skagit Valley Treaty	(22)	(23)	(24)	(25)
Ancillary Services and Miscellaneous Revenue	(4)	(5)	(6)	(6)
Total Other Revenues	**(26)**	**(28)**	**(30)**	**(31)**
Net Costs	**1,000**	**984**	**1,000**	**1,004**
Add: Return on Equity	**154**	**160**	**180**	**192**
Forecast Heritage Payment Obligation	**$1,154**	**$1,144**	**$1,180**	**$1,196**

Table 2: Forecast Heritage Payment Obligation 2005 – 2007 ($millions)

BC Hydro developed the cost and revenue forecasts shown in Table 2 using the same budgeting, planning and forecasting processes it uses to develop the 5 year BC Hydro Service Plan, and its yearly internal line-of-business service plans. The only exception is that the cost of energy forecasts in Table 2 are based on the delivery of 49,000 GWh per year.

3.7.3 Forecast Heritage Payment Obligation Fiscal 2008 – 2014

Table 3 summarizes the forecast Heritage Payment Obligation for fiscal 2008 to 2014 (fiscal years ending March 31, 2008 – 2014). Detail on the cost components is found in Appendix F. Cost and revenue forecasts in Table 3 are extrapolated from fiscal 2007 on the following assumptions:

- operating costs including business sustaining costs are held constant;
- average inflows through the period;

- $25 million per year for growth capital to take advantage of Resource Smart opportunities, including Revelstoke Unit 5;

- annual sustaining capital expenditure is 1% of net replacement value of assets of approximately $18.4 billion and increasing by approximately 2% per year (necessary to ensure the continued availability of aging assets); and

- depreciation expenses and finance charges are derived from capital expenditure levels.

	Heritage Contract						
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Heritage Contract Costs							
Cost of Energy	$434	$434	$432	$429	$432	$425	$425
Operating Costs	166	166	166	166	166	166	166
Asset Related Expenses	411	420	430	439	448	457	467
GRTA Expenses	43	43	43	43	43	43	43
Total Heritage Contract Costs	1,054	1,063	1,071	1,077	1,089	1,091	1,101
Less Other Revenues							
Skagit Valley Treaty	(25)	(25)	(25)	(25)	(25)	(25)	(25)
Ancillary Services and Other Miscellaneous Revenue	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Total Other Revenues	(30)	(30)	(30)	(30)	(30)	(30)	(30)
Net Costs	1,024	1,033	1,041	1,047	1,059	1,061	1,071
Add: Return on Equity	182	189	197	205	213	221	230
Forecast Heritage Payment Obligation	**$1,206**	**$1,222**	**$1,238**	**$1,252**	**$1,272**	**$1,282**	**$1,301**

Table 3: Forecast Heritage Payment Obligation 2008 – 2014 ($millions)

APPENDIX A: TERMS OF REFERENCE

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 0253 , Approved and Ordered MAR 25 2003

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that pursuant to section 5 of the *Utilities Commission Act*, the Lieutenant Governor in Council requests the British Columbia Utilities Commission to provide recommendations relating to the matter of a heritage contract and other electricity policy matters as specified in the Terms of Reference attached as Schedule A to this Order.

Neufeld

Minister of Energy and Mines

G Campbell

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- *Utilities Commission Act, s. 5*

Other (specify):-

March 11, 2003

341 /2003/6

SCHEDULE A

TERMS OF REFERENCE

IN THE MATTER OF the Utilities Commission Act ("the *Act*")

and

IN THE MATTER OF Recommendations Relating to a Heritage Contract for BC Hydro's Existing Generation Resources, and to Stepped Rates and Transmission Access

WHEREAS, under Section 5(1) of the *Act*, the Lieutenant Governor in Council ("LGIC") may request the BC Utilities Commission ("BCUC" or "Commission") to provide advice on any matter the LGIC specifies; and

WHEREAS on November 25, 2002, the Province of British Columbia announced its new Energy Plan, the four cornerstones of which are: low electricity rates and public ownership of BC Hydro; secure and reliable energy supply; more private sector opportunities; and environmental responsibility and no nuclear power sources; and

WHEREAS the Energy Plan outlines several Policy Actions designed to ensure British Columbians have continued access to sufficient supplies of dependable low-cost electricity; and

WHEREAS the Energy Plan provides in Policy Action #5 that the Commission will once again regulate the rates charged by BC Hydro; and

WHEREAS the Energy Plan contemplates that the Commission should conduct an inquiry to develop and refine certain policy areas relating to regulation of BC Hydro prior to the commencement of its review of BC Hydro's rates and should submit a report to government describing changes to legislation and regulations that it believes are desirable in that connection; and

WHEREAS the Energy Plan contemplates a full review of BC Hydro's rate levels based on an application to be filed before March 31, 2004; and

WHEREAS the Energy Plan provides in Policy Action #1 that a legislated heritage contract will be created between BC Hydro's generation line of business and its distribution line of business for a term of ten years initially; and

WHEREAS the Energy Plan provides in Policy Action #2 that an appropriate level of trade revenues, net of incremental costs properly allocated by BC Hydro for internal management purposes, will continue to be assigned for rate-setting purposes to help maintain low and stable rates for BC consumers; and

WHEREAS trade revenues, net of incremental costs properly allocated by BC Hydro for internal management purposes, above $200 Million in any year will flow to the government for the benefit of all British Columbians; and

WHEREAS the Energy Plan contemplates large industrial or transmission rate customers and energy suppliers having access to transmission for the purpose of acquiring and providing energy for all or a portion of their needs based on principles to be established; and

WHEREAS the Energy Plan provides in Policy Direction #21 that new rate structures should be developed to send better price signals to large electricity consumers.

NOW THEREFORE the Commission shall conduct an inquiry pursuant to Section 5 of the *Act* in compliance with the following Terms of Reference:

1. The general purpose of the inquiry is to obtain the Commission's Recommendations on what changes, if any, should be made to legislation, regulations, special directions or special directives affecting BC Hydro and/or the Commission in order to implement the Energy Plan in connection with the issues identified in paragraphs 3 and 4 of these Terms of Reference.

   For greater certainty, the Commission shall provide Recommendations on whether the current rate stabilization account provided for in Special Direction 8 and Special Directive 4 should be eliminated and, if so, whether any alternative form of deferral account mechanism should be considered to implement the Commission's Recommendations with respect to paragraph 3 of the Terms of Reference, and on whether there is a need for revisions to paragraph 3 of Special Direction 8 to implement the Commission's Recommendations with respect to paragraph 4 of the Terms of Reference.

2. With respect to Policy Action #1 from the Energy Plan, the Commission shall make Recommendations concerning the terms and conditions which should be contained in a Heritage Contract based on the following assumptions:

   (a) The resources and obligations to which the Heritage Contract shall relate are those set out in Schedule A;

   (b) The classes of customers that are eligible to benefit from the Heritage Contract are those set out in Schedule B, as may be amended from time to time to reflect the introduction of new rate structures or options;

   (c) Except as expressly provided herein, the determination of rates for customers identified in Schedule B will not be considered until after the Commission's Recommendations have been provided to the Lieutenant Governor in Council pursuant to these Terms of Reference; and

   (d) The quantity of energy producible from the resources shall be determined assuming average water conditions for the duration of the Heritage Contract.

3. The Commission shall make specific Recommendations relating to the following matters concerning the Heritage Contract:

(a) The quantity of energy which will be available under the Heritage Contract;

(b) The cost of supplying the energy identified in subparagraph (a), including:

(i) All costs properly allocated to that activity by BC Hydro for internal management purposes;

(ii) An allowance for return on BC Hydro's equity invested in the assets identified in Schedule A; and

(iii) The portion, if any, of transmission assets that should be deemed to be "generation related" and which should be included in the heritage contract for costing purposes, and ultimately to be recovered in electricity rates of BC Hydro's distribution line of business;

(c) The price that BC Hydro's distribution line of business should be deemed to pay for the quantity of energy identified in subparagraph (a);

(d) Having regard for the considerations referred to in 3(h) below, the provisions that should be included in the Heritage Contract relating to capacity, shape, and scheduling flexibility to fairly allocate the benefits arising from the resources listed in Schedule A under average water arising from the resources listed in Schedule under average water conditions between the customers listed in Schedule B and BC Hydro;

(e) The principles and impacts of providing ancillary services requirements to BC Transmission Corporation;

(f) The extent to which the quantity, price or other terms or conditions relating to the acquisition of the heritage energy by the distribution line of business should vary during the initial ten-year term of the Heritage Contract:

(i) by reason of changed circumstance;

(ii) by reason of a determination that the allocation identified in subparagraph (b) is not appropriate;

(iii) by reason of capital maintenance or similar investments not intended to materially affect the productive capacity of the assets listed in Schedule A; and;

(iv) by reason of any other factor the Commission believes is important;

(g) The renewal provisions which should apply to the continuation of the Heritage Contract after the expiry of an initial ten-year term;

(h) The appropriate regulatory framework:

(i) which provides incentives to, and allows, BC Hydro and its affiliates and subsidiaries to make timely decisions to maximize trade revenues net of costs properly allocated by BC Hydro for internal management purposes in light of the determinations made pursuant to subparagraph (d); and

(ii) to allocate amounts of trade revenue, net of incremental costs properly allocated by BC Hydro for internal management purposes, up to a maximum of $200 million per year, between BC Hydro and customers listed in Schedule B in a manner that provides rewards to the party that takes the risk associated with realizing those rewards while minimizing the expenses and delays associated with regulatory oversight of activities relating to trade;

(i) The determination of the state date of the Heritage Contract including potential adjustments at the start of the Heritage Contract relating to capacity, shape and scheduling flexibility.

4. The Commission shall make specific Recommendations relating to any changes it believes are desirable in the rates of transmission voltage customers to accomplish the objectives set out in the Energy Plan, including:

(a) The terms and conditions that should govern existing and new large industrial or transmission rate customers' access to transmission for the purpose of acquiring power from other energy suppliers' generation;

(b) The detailed provisions of new stepped rate schedules as more fully described in the Energy Plan, including load aggregation by a customer with facilities at more than one location; and

(c) The principles which should govern the terms and conditions under which large industrial or transmission rate customers wishing to obtain generation from alternate suppliers may decline to obtain service from BC Hydro or may apply to obtain service from BC Hydro thereafter.

5. For the purpose of conducting this inquiry and obtaining stakeholder input, the Commission may seek and employ expert advice on various subjects and shall employ any or all of the powers provided to it under the *Act* and, in particular, may, in its sole discretion, employ diverse procedures to resolve specific issues within the Terms of Reference, including, as appropriate, workshops, mediation, dispute resolution mechanisms, pre-hearing conferences, and oral and written public hearings.

6. The Commission shall require BC Hydro to file by April 30, 2003 a proposal that identifies the detailed Recommendations and reasons that BC Hydro believes should be contained in the Commission's report to the Lieutenant Governor in Council.

7. The Commission shall invite comment on BC Hydro's proposal from all affected stakeholders and identify appropriate processes to consider it in compliance with paragraph 5.

8. The Commission shall submit a report to the Lieutenant Governor in Council by no later than October 17, 2003, listing its Recommendations and the reasons for the Recommendations, including proposed legislation, regulations, special directions to the Commission or special directives to BC Hydro, as it thinks fit.

9. The Commission shall consider any other matters that may be specified in supplementary Terms of Reference issued by the Lieutenant Governor in Council pursuant to Section 5 of the *Act*.

March 7, 2003

SCHEDULE A
BC Hydro's Existing Facilities

Resources

(a) Electric Facilities

Aberfeldie
Alouette
Ash River
Bridge River
Buntzen/Coquitlam
Cheakamus
Clowhom
Duncan
Elko
Falls River
G.M. Shrum
Hugh Keenleyside Dam (Arrow Reservoir)
John Hart
Jordan
Kootenay Canal
Ladore
La Joie
Mica
Peace Canyon
Puntledge
Revelstoke
Ruskin
Seton
Seven Mile
Shuswap
Spillimacheen
Stave Falls
Strathcona
Wahleach
Walter Hardman
Whatshan

(b) Thermal Facilities

Burrard Thermal
Fort Nelson
Prince Rupert

Other Rights and Obligations

Columbia River Treaty and Entity Agreements made thereunder
Skagit Valley Treaty
Canal Plant Agreement
Keenleyside Entitlement Agreement
Replacement Electricity Supply Agreement between the Province and Alcan
Power for Jobs

SCHEDULE B

Residential Service	General Service	Irrigation Service	Street Lighting Service	Transmission Service
1101	1200	1401	1701	1821
1103	1201		1702	1848
1105	1205		1703	1852
1107	1206		1704	3808
1111	1207		1755	TS #1
1113	1210		1761	
1117	1211		1770	
1121	1220			
1123	1222			
1127	1223			
1131	1233			
1132	1234			
1133	1241			
1134	1242			
1135	1243			
1137	1244			
1148	1255			
	1256			
	1265			
	1266			
	1277			
	1278			
	1288			

APPENDIX B: ORDER G-23-03

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-23-03

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

British Columbia Hydro and Power Authority
Proposal regarding a Heritage Contract for B.C. Hydro's Existing Generation Resources
and regarding Stepped Rates and Transmission Access

BEFORE: R.H. Hobbs, Commissioner)
K.L. Hall, Commissioner) April 1, 2003

O R D E R

WHEREAS:

A. On November 25, 2002, the Minister of Energy and Mines released "Energy for Our Future: A Plan for BC" ("the Energy Plan"); and

B. The Energy Plan contemplates that the Commission should conduct an inquiry to develop and refine certain policy areas relating to regulation of British Columbia Hydro and Power Authority ("B.C. Hydro") prior to the commencement of its review of B.C. Hydro's rates, and should submit a report to the Lieutenant Governor in Council by October 17, 2003 describing proposed changes to legislation and regulations that it believes are desirable in that connection; and

C. On March 25, 2003 the Province, by Order in Council No. 0253, issued Terms of Reference for an Inquiry relating to a Heritage Contract for B.C. Hydro's Existing Generation Resources and to Stepped Rates and Transmission Access; and

D. The Terms of Reference direct the Commission to conduct an Inquiry pursuant to Section 5 of the Utilities Commission Act; and

E. The general purpose of the Inquiry is to obtain the Commission's recommendations on what changes, if any, should be made to legislation, regulations, special directions or special directives affecting B.C. Hydro and/or the Commission in order to implement the Energy Plan in connection with specific issues identified in the Terms of Reference; and

F. The Terms of Reference direct the Commission to require B.C. Hydro to file by April 30, 2003, a proposal that identifies the detailed recommendations and reasons that B.C. Hydro believes should be contained in the Commission's report to the Lieutenant Governor in Council; and

G. The Commission requires that a regulatory process for the Inquiry be established.

NOW THEREFORE the Commission orders as follows:

1. B.C. Hydro is directed to file by April 30, 2003, a proposal that identifies the detailed recommendations and reasons that B.C. Hydro believes should be contained in the Commission's report to the Lieutenant Governor in Council.

.../2

2. B.C. Hydro is further directed to publish, as soon as possible, in display-ad format, the Notice attached as Appendix B to this Order, in British Columbia daily newspapers plus the British Columbia editions of the Globe & Mail, and the National Post regarding the Province's direction to the Commission for an Inquiry and the B.C. Hydro proposal.

3. B.C. Hydro is directed to make its proposal available to the public for viewing at its Head office and at its Regional Offices in Victoria, Nanaimo, Prince George, Vernon and Castlegar.

4. To allow for distribution of the B.C. Hydro proposal to Intervenors on April 30, 2003, persons who intend to actively participate in the Inquiry should inform the Commission, in writing, of their intention to intervene in the Inquiry by April 22, 2003; and

5. Persons who do not intend to actively participate in the Inquiry but wish to receive B.C. Hydro's Executive Summary, all Orders issued, and the Final Report should inform the Commission, in writing of the intention to be an Interested Party by April 22, 2003.

6. A Regulatory Agenda and Timetable is attached as Appendix A to this Order. The Commission will advise registered participants of the times and locations of the workshop, pre-hearing conference and public hearing following receipt of the B.C. Hydro proposal.

7. Intervenors intending to apply for participant assistance must submit a budget estimate by Monday, May 12, 2003 consistent with the Commission's Participant Assistance/Cost Award Guidelines. Copies are available upon request or can be downloaded from the Commission's web site at http://www.bcuc.com/bcuc/paca.html.

DATED at the City of Vancouver, in the Province of British Columbia, this 3rd day of April 2003.

BY ORDER

Original signed by:

Robert H. Hobbs
Commissioner

Attachments

Orders/BCH/Heritage Contract/Init Tmbl

APPENDIX A
to Order No. G-23-03
Page 1 of 1

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
Proposal regarding a Heritage Contract for B.C. Hydro's Existing Generation Resources
and regarding Stepped Rates and Transmission Access

REGULATORY AGENDA AND TIMETABLE

ACTION	DATES (2003)
Registration of Intervenors or Interested Parties	April 22
B.C. Hydro files proposal and any written testimony	April 30
Commission Staff Workshop (Note 1)	May 13
Information Requests to B.C. Hydro	May 16
B.C. Hydro Responses to Information Requests	May 29
Intervenor written submissions and any written testimony	June 6
Information Requests to Intervenors	June 13
Intervenor Responses to Information Requests	June 27
Commission Panel circulates draft public hearing Issues List	July 3
Pre-hearing Conference (Note 2)	July 7
Commission Panel Order finalizing public hearing Issues List	July 9
Supplementary Evidence of all Parties relating to Hearing Issues	July 16
Regional Inquiry Sessions:	
Victoria	July 21
Prince George	July 23
Kelowna	July 25
Vancouver public hearing	July 28-August 8
B.C. Hydro Written Argument	August 15
Intervenor Written Argument	August 22
B.C. Hydro Reply Argument	August 29
Final Report to Lieutenant Governor in Council	October 17

Note 1: At the workshop on May 13, the dates for the public hearing in Vancouver and the timing of final argument will be discussed.

Note 2: The pre-hearing conference is a hearing before the Commission Panel to give all Parties the opportunity to make submissions on the issues that they believe should be canvassed at the public hearing, together with submissions on any other issues for the public hearing.

The Time and Place of the workshop, pre-hearing conference and public hearing will be communicated to intervenors and interested parties at a later date.

APPENDIX B
to Order No. G-23-03
Page 1 of 2

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NOTICE OF AN INQUIRY BY THE BRITISH COLUMBIA UTILITIES COMMISSION

BACKGROUND

On November 25, 2002, the Minister of Energy and Mines released "Energy for Our Future: A Plan for BC" ("the Energy Plan"). The Energy Plan anticipated an Inquiry by the British Columbia Utilities Commission into certain policy areas relating to regulation of British Columbia Hydro and Power Authority ("B.C. Hydro") prior to its review of B.C. Hydro's rates.

On March 25, 2003, the Province issued Terms of Reference directing the Commission to conduct an Inquiry relating to a heritage contract for B.C. Hydro's existing generation resources, and to stepped rates and transmission access. The general purpose of the Inquiry is to obtain the Commission's recommendations on what changes, if any, should be made to legislation, regulations, special directions or special directives affecting B.C. Hydro and/or the Commission in order to implement these components of the Energy Plan.

The Terms of Reference direct the Commission to require B.C. Hydro to file by April 30, 2003, a Proposal that identifies the detailed recommendations and reasons that B.C. Hydro believes should be contained in the Commission's report to the Lieutenant Governor in Council. The Terms of Reference can be viewed on the BCUC's web site at www.bcuc.com.

HOW TO PARTICIPATE

Persons who intend to actively participate in the Inquiry should register as Intervenors with the Commission, in writing, by Friday, April 22, 2003 identifying their interest in the Proposal, and providing an e-mail address if available. Intervenors will receive copies of the Proposal, all Orders issued, all correspondence and filed documentation, and the Final Report.

Persons not intending to actively participate, but who have an interest in the Proposal, should register as Interested Parties with the Commission, in writing, by Friday, April 22, 2003. Interested Parties will receive a copy of the B.C. Hydro's Executive Summary, all Orders issued, and the Final Report.

.../2

PUBLIC INSPECTION OF THE DOCUMENTS

Once filed with the Commission, the B.C. Hydro Proposal and any supporting material will be made available for inspection at the following locations:

British Columbia Hydro and Power Authority
Head Office: 17th Floor - 333 Dunsmuir Street, Vancouver, B.C.
(604) 623-4046

Regional Offices: In Victoria, Nanaimo, Vernon, Castlegar and Prince George

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Vancouver, B.C.

The Proposal will also be available for viewing on B.C. Hydro's web site at *http://www.bchydro.com* after it has been filed with the Commission.

FURTHER INFORMATION

For further information, please contact Mr. Robert J. Pellatt, Commission Secretary, or Mr. Jim Fraser, Manager, Strategic Services as follows:

Telephone:	(604) 660-4700	Facsimile:	(604) 660-1102
B.C. Toll Free:	1-800-663-1385	E-Mail:	Commission.Secretary@bcuc.com

APPENDIX C: HERITAGE CONTRACT

WHEREAS on November 25, 2002, the Province of British Columbia announced its new Energy Plan; and

WHEREAS the Energy Plan outlines several Policy Actions designed to ensure British Columbians have continued access to sufficient supplies of dependable low-cost electricity; and

WHEREAS the Energy Plan provides in Policy Action #1 that a legislated heritage contract will be created between BC Hydro's generation line of business and its distribution line of business for a term of ten years initially.

THEREFORE, BCH Distribution and BCH Generation agree as follows.

Definitions

1. In this Agreement:

   (a) "BC Hydro" means the British Columbia Hydro and Power Authority;

   (b) "Commission" means the British Columbia Utilities Commission;

   (c) "BCH Distribution" means BC Hydro's distribution line of business;

   (d) "BCH Generation" means BC Hydro's generation line of business;

   (e) "Heritage Electricity" means the capacity, energy and ancillary services that BCH Generation is required to supply to BCH Distribution under this Agreement;

   (f) "Heritage Energy" means 49,000 GWh per year, less the energy delivered under the Skagit Valley Treaty, as may be adjusted from time to time in accordance with Section 8;

   (g) "Heritage Payment Obligation" means the annual payment determined in accordance with the procedure set out in Schedule A to this Agreement, as may be adjusted from time to time in accordance with Section 8;

   (h) "Heritage Resources" means the Electric Facilities and Thermal Facilities prescribed in Schedule A to the Terms of Reference, together with the related civil works and plant;

   (i) "Agreement" means this Heritage Contract including Schedule A;

   (j) "Terms of Reference" means Schedule A, Terms of Reference, to British Columbia Order in Council No. 0253, Approved and Ordered March 25, 2003; and

   (k) "Year" means fiscal year.

Electricity Supply

2. BCH Generation will provide the full capacity of the Heritage Resources to BCH Distribution on a priority call basis.

3. BCH Generation will supply up to the Heritage Energy to BCH Distribution, as required by BCH Distribution.

4. BCH Generation will deliver the Heritage Energy to BCH Distribution at the various points of interconnection of the generating stations included in the Heritage Resources with the BC Hydro transmission grid or at points of interconnection with other utilities, as appropriate.

5. BCH Distribution will be responsible for obtaining transmission services.

Ancillary Services

6. BCH Distribution may use the capacity available to it under Section 2 to either deliver energy to meet customer demand or to satisfy its ancillary service obligations.

Payment

7. On an annual basis, BCH Distribution will pay BCH Generation an amount equal to the Heritage Payment Obligation.

Adjustment

8. The parties acknowledge that the Commission may, by Order, adjust the Heritage Energy or Heritage Payment Obligation and any such adjustment will automatically adjust the Heritage Energy or Heritage Payment Obligation, respectively, under this Agreement without further action by the parties.

Information Exchange and Cooperation

9. Each party will continue to freely provide the other with any requested information to facilitate the coordinated and optimal operation of the BC Hydro system.

Dispute Resolution

9. In the spirit of coordinated operation of the BC Hydro system, the parties will make reasonable efforts to resolve disputes arising in relation to this Agreement at the staff level through implementation planning, cooperation and consultation. Issues will be elevated to more senior management levels within each party as needed to achieve timely resolution.

Term and Termination

11. This Agreement is effective for a minimum of 10 years, and thereafter until terminated by a government policy direction, with 4 years notice.

Dated this ____ day of ________, 2004.

________________________	________________________
BC Hydro Distribution	BC Hydro Generation

SCHEDULE A
HERITAGE PAYMENT OBLIGATION

The Heritage Payment Obligation is the sum of the following cost and revenue components related to the Heritage Resources actually incurred by BCH Generation in a Year:

(i) cost of energy: the cost of water fees and energy purchases (gas and electricity) required to supply Heritage Electricity;

(ii) operating costs: all costs of operating and maintaining the Heritage Resources, including an allocation of corporate costs;

(iii) asset related expenses: the costs of owning the Heritage Resources including depreciation, interest, finance charges and other asset related expenses;

(iv) generation-related transmission assets: all costs or payments related to any generation-related transmission required by the Heritage Resources;

(v) return on equity: the appropriate return on equity, currently based on Special Direction #8, on investments in Heritage Resources;

less,

(vi) other revenues: any revenues BCH Generation receives from other services provided from the Heritage Resources including revenues related to Skagit Valley Treaty obligations, revenues from provision of ancillary services to the transmission operator in respect of third party use of the transmission system, revenues from sales of surplus hydro energy, and other miscellaneous revenues.

APPENDIX D: GLOSSARY OF DEFINED TERMS

Heritage Beneficiaries means all current and future British Columbians taking service from BC Hydro under the rate schedules listed in Schedule B of the Terms of Reference (sub-section 1.2.2);

Heritage Deferral Account means the regulatory accounting mechanism that BC Hydro proposes to use to capture the difference between the Heritage Payment Obligation and the forecast Heritage Payment Obligation, and the difference between Trade Income and forecast Trade Income (sub-section 2.1.2);

Heritage Electricity means the capacity, energy and ancillary services BC Hydro's Generation line of business is obliged to provide to BC Hydro's distribution line of business under the Heritage Contract (sub-section 2.1.3, and Appendix C);

Heritage Energy means 49,000 GWh, an amount representative of the reliable capability of the Heritage Resources under average water conditions (sub-section 2.1.3 and section 3.1);

Forecast Heritage Reference Price means the quotient of the average current forecast of the Heritage Payment Obligation over the 10 years of the Heritage Contract, and Heritage Energy, being $25.30 per MWh (sub-section 2.1.3. and section 3.7);

Heritage Payment Obligation means the sum of the cost and revenue components related to the Heritage Resources and described in Schedule A to the Heritage Contract that equal the actual cost of supplying Heritage Electricity (sub-section 2.1.3 and Appendix C);

Heritage Resources means the resources listed in Schedule A to the Terms of Reference, together with the related civil works and plant (sub-section 1.2.2);

Trade Income means the financial benefits of electricity trade that accrue to the Heritage Beneficiaries and that are subject to a $0 floor and a $200 million ceiling, the calculation of which is described in section 3.3.

APPENDIX E: ILLUSTRATION OF HERITAGE DEFERRAL ACCOUNT

	Units	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Forecast Heritage Energy											
Hydro Generation	GWh	46,635	46,635	46,635	46,635	46,635	46,635	46,635	46,635	46,635	46,635
Market Purchases or Thermal Generation	GWh	2365	2365	2365	2365	2365	2365	2365	2365	2365	2365
Heritage Energy	GWh	49,000	49,000	49,000	49,000	49,000	49,000	49,000	49,000	49,000	49,000
Actual Heritage Energy (Illustrative)											
Hydro Generation (1985-1994)	GWh	47,420	39,720	51,420	49,120	41,420	46,320	48,920	50,120	42,320	43,420
Market Purchases or Thermal Generation	GWh	1,580	9,280	495	495	7,580	2,680	495	495	6,680	5,580
Surplus Hydro Energy				(2,915)	(615)			(415)	(1,615)		
Actual Heritage Energy	GWh	49,000	49,000	49,000	49,000	49,000	49,000	49,000	49,000	49,000	49,000
Deferral Adjustment											
Forecast Heritage Payment Obligation	A	$ 1,144	$ 1,180	$ 1,196	$ 1,206	$ 1,222	$ 1,238	$ 1,252	$ 1,272	$ 1,282	$ 1,301
Heritage Payment Obligation (Illustrative)	B	$ 1,078	$ 1,515	$ 939	$ 1,057	$ 1,478	$ 1,235	$ 1,117	$ 1,078	$ 1,477	$ 1,441
Deferral Adjustment	A - B = C	$ 66	$ (335)	$ 257	$ 149	$ (256)	$ 3	$ 135	$ 194	$ (195)	$ (140)
Deferral Account Continuity											
Opening Balance	D	$	$ 66	$ (265)	$ (27)	$ 120	$ (128)	$ (134)	$ (8)	$ 185	$ 3
Additions	C	66	(335)	257	149	(256)	3	135	194	(195)	(140)
Interest @7%	E	0	4	(19)	(2)	8	(9)	(9)	(1)	13	0
Closing Balance	D+C+E	$ 66	$ (265)	$ (27)	$ 120	$ (128)	$ (134)	$ (8)	$ 185	$ 3	$ (137)

In this illustration, hydro generation based on hydro generation from 1985 to 1994 The balance of the heritage energy is allocated to market or gas purchases, resulting in variances in Heritage Payment Obligation

APPENDIX F: DETAIL REGARDING FORECAST HERITAGE PAYMENT OBLIGATION

A. Cost of Energy Component of Forecast Heritage Payment Obligation

The cost of energy component of the Heritage Payment Obligation includes all direct energy related costs incurred in the generation of electricity such as water license fees, fuel and transportation costs for thermal generation, and the cost of electricity purchases for BCH Generation's use. The following tables summarize those components for fiscal 2005-07 (Table 4) and fiscal 2008 – 2014 (Table 5).

	Reference	**Heritage Contract**		
	2004	**2005**	**2006**	**2007**
Water Rental	$258	$263	$263	$263
Gas Purchases – Fort Nelson	15	14	11	10
Electricity / Gas Purchases	138	132	124	128
Gas Transportation – Burrard	10	10	10	10
Transmission - Skagit	17	17	17	17
Compensation & Mitigation	3	5	5	6
Cost of Energy	**$441**	**$441**	**$430**	**$434**

Table 4: Forecast Cost of Energy Fiscal 2005 to 2007 ($ millions)

	Heritage Contract						
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Water Rental	$263	$263	$263	$263	$263	$263	$263
Gas Purchases – Fort Nelson	10	10	10	10	9	9	10
Electricity / Gas Purchases	128	128	126	123	127	120	119
Gas Transportation - Burrard	10	10	10	10	10	10	10
Transmission – Skagit	17	17	17	17	17	17	17
Compensation & Mitigation	6	6	6	6	6	6	6
Cost of Energy	**$434**	**$434**	**$432**	**$429**	**$432**	**$425**	**$425**

Table 5: Forecast Cost of Energy Fiscal 2008 – 2014 ($ millions)

The cost of energy forecasts for each year, fiscal 2005 to 2014, are based on delivery of 49,000 GWh of Heritage Energy comprised of 46,635 GWh hydro generation and 2,365 GWh thermal generation or market purchases, as explained in section 3.2.

Water rentals are levied by the Province on hydroelectric generating capacity and use of water based on actual generation output. Water rental rates are currently $3.453/KW of capacity and $1.036/MWh for the first 160 GWh and $4.835/MWh for plant output thereafter, but are indexed to BC Hydro's rate schedules. To arrive at the $263 million figure, current water rental rates, unadjusted for any future rate increases are applied to 46,635 GWh of average energy hydro generation.

Market purchases of gas or electricity make up the balance of the 2,365 GWh of Heritage Energy. 2005-2007 purchases are costed at BC Hydro's current forecast market cost of electricity. 2008 – 2014 purchases are represented in 2003 dollars.

Gas transportation costs under Bypass Transportation Agreement for Rate Schedule 22, dated the 27th day of November, 1998 between BC Gas Utility Ltd. and BC Hydro, are included as a component of cost of energy. The contract provides firm gas transportation to Burrard for a thirty year period, from November 1999 to November 2028. Costs are based on contracted amounts.

Transmission costs relating to BC Hydro's obligations under the Skagit Valley Treaty are included in the cost of energy. They are comprised of approximately $13 million per year for wholesale transmission in British Columbia, and about $4 million per year for wholesale transmission in the United States, based on current wheeling rates.

Compensation and mitigation programs include BC Hydro's commitments to fund three regional fish and wildlife compensation programs. Current costs of $3 million per year are expected to increase to $6 million by fiscal 2007, and are assumed to remain constant thereafter.

B. Operating Cost Component of Forecast Heritage Payment Obligation

Operating costs include maintenance, operating, environmental, regulatory and management costs associated with the Heritage Resources. The following tables summarize the major components for fiscal 2005 – 2007 (Table 6) and fiscal 2008 – 2014 (Table 7).

	Reference	Heritage Contract		
$ Millions	**2004**	**2005**	**2006**	**2007**
Maintenance	$67	$67	$67	$67
Other Operating	59	58	59	59
Business Sustaining Costs	36	33	42	40
Total Operating Costs	**$162**	**$158**	**$168**	**$166**

Table 6: Forecast Operating Cost Fiscal 2005 to 2007
($ millions)

	Heritage Contract						
$ Millions	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Maintenance	$67	$67	$67	$67	$67	$67	$67
Other Operating	59	59	59	59	59	59	59
Business Sustaining Costs	40	40	40	40	40	40	40
Total Operating Costs	**$166**	**$166**	**$166**	**$166**	**$166**	**$166**	**$166**

Table 7: Forecast Operating Cost Fiscal 2008-2014
($ millions)

Maintenance costs are shown in 2003 dollars and include labour and materials associated with maintenance and dam safety programs for generating facilities. Generation maintenance is the process of ensuring that equipment is kept in, or returned to, good operating order. It includes all costs to inspect, adjust, or repair or replace parts and run tests to determine that repairs were properly made and that the repaired item is ready for service. It also includes the cost of repairing assets that fail. Due to aging facilities the actual cost of maintenance will likely be higher than reflected in this forecast as costs are expected to increase in real terms.

Other operating costs, also shown in 2003 dollars, include labour associated with planning, operating and managing generation operations. Operations is the process of producing or enabling the production of energy and ancillary services from generating facilities which are otherwise in good operating order. Also included in this category are environmental, regulatory and social costs that comprise all activities associated with managing regulatory, environmental, and community issues as well as those activities that are required to maintain the franchise to use the water. These include fisheries and wildlife issues, recreational facilities and visitor centres.

Business sustaining costs are corporate services and costs collected at the corporate level that are allocated between BC Hydro's lines of business. The allocations, depending on the type of cost, are based on headcount, operations, maintenance and administration expenditures, sustaining capital expenditures and square-foot usage of corporate buildings. Costs are in nominal dollars for the period 2004 – 2007, and are assumed constant thereafter.

C. Asset Related Expenses Component of Forecast Heritage Payment Obligation

Asset related expenses include depreciation and amortization, financing and net of interest during construction costs, taxes and grants. The following tables summarize the major components for fiscal 2005 – 2007 (Table 8) and fiscal 2008 – 2014 (Table 9).

	Reference	Heritage Contract		
	2004	2005	2006	2007
Depreciation & Amortization	$111	$110	$112	$114
Taxes and Grants	28	29	29	29
Finance Costs less Interest During Construction	241	231	248	249
Total Asset Related Expenses	**$380**	**$370**	**$389**	**$392**

Table 8: Forecast Asset Related Expenses Fiscal 2005 to 2007
($ millions)

	Heritage Contract						
	2008	2009	2010	2011	2012	2013	2014
Depreciation & Amortization	$117	$120	$125	$129	$133	$137	$142
Taxes and Grants	29	29	29	29	29	29	29
Finance Costs less Interest During Construction	265	271	276	281	286	291	296
Total Asset Related Expenses	**$411**	**$420**	**$430**	**$439**	**$448**	**$457**	**$467**

Table 9 Forecast Asset Related Expenses Fiscal 2008-2014
($ millions)

Depreciation and amortization expenses are based on capital assets in service which are depreciated on an individual or pooled basis over the expected useful lives of the assets (generally using the straight-line method). Depreciation includes provisions for costs of net-of-expected recoveries for future asset removal and site restoration arising from retirement of capital assets. Capital expenditures are approximately 1% of replacement value, increasing by approximately 2% per year.

Financing costs less interest during construction consist primarily of interest on debt securities, amortization of deferred debt costs and other expenses, less income from sinking funds and interest during construction. These costs have been allocated based on the Heritage Resource proportion of the total of BC Hydro's debt balance. Finance charges are capitalized on construction in progress at rates equivalent to BC Hydro's charge cost of borrowing.

Interest during construction is capitalized on construction in progress at rates equivalent to BC Hydro's average annual cost of borrowing. The rate takes into consideration annual interest costs plus foreign exchange adjustments and amortization of premiums, discounts and issue costs.

Taxes and grants are paid to the Province and municipalities based on the value of all assessable property, and in lieu of general, local improvement and regional district levies, respectively. Costs are assumed constant.

D. GRTA Cost Component of Forecast Heritage Payment Obligation

BC Hydro proposes to include in the Heritage Payment Obligation an amount in respect of BC Hydro's Generation Related Transmission Assets (GRTA) that was determined in a manner consistent with the Commission's April 23, 1998 Wholesale Transmission Services decision. That amount is $43.3 million. It is the difference between the total "transmission revenue requirement" and the smaller portion of the "transmission revenue requirement" reflected in current wholesale transmission rates. The amount may be thought of as a "GRTA revenue requirement".

BC Hydro proposes that the GRTA amount be fixed at the proposed amount for the duration of the Heritage Contract, and that it not be associated with any specific set of assets, regardless of what BC Hydro assets eventually come under the operational control of the BC Transmission Corporation. This approach preserves the rate impact of the 1998 decision, while eliminating any operating complications due to having to differentiate between GRTA transmission line facilities and other transmission line facilities. That is, this approach will permit the wholesale transmission tariff to be applied consistently to all transmission line facilities.

E. Skagit Ancillary Services and Miscellaneous Revenues Component of Forecast Heritage Payment Obligation

Under the Skagit Valley Treaty, BC Hydro is required to deliver approximately 310 GWh of electricity to Seattle City Light each year for an 80-year period ending in fiscal 2066. Including losses, the annual generation requirement is approximately 340 GWh. In return, BC Hydro receives approximately US $22 million each year for a 35-year period ending in fiscal 2020 and US $1 million (adjusted for inflation) each year for an 80-year period ending in fiscal 2066. The revenue recognized annually is approximately CDN $25 million. Funds received in excess of deliveries are shown as deferred revenue in the equity section of BC Hydro's balance sheet.

BC Hydro anticipates earning about $3 million per year from the sale of ancillary services to BC Transmission Corp arising from third-party use of the transmission system, based on historical sales and adjusted for future growth in sales.

Under average water conditions BC Hydro does not forecast any revenue from sales of surplus hydro energy.

Other miscellaneous revenues include revenues owned from water sold to the Greater Vancouver Regional District from Coquitlam reservoir, and the sale of steam from Burrard Thermal. These revenues are estimated to range between $1 to $3 million per year.

F. Return on Equity Component of Forecast Heritage Payment Obligation

In BC Hydro's most recent revenue requirement decision (1994/95), BC Gas Utility Ltd. (BC Gas) was found to be the most comparable utility to BC Hydro. Consequently, the allowed rate of return on a pre-income tax basis for BC Gas is used in the determination of BC Hydro's rate of return. No change to this determination is proposed in this proposal. Any proposed change would be made in the next revenue requirement application.

In this proposal the same rate of return has been used, as BC Hydro continues to be regulated as consolidated BC Hydro. No differentiation in either the debt–to-equity ratio or return on equity between consolidated BC Hydro and the BCH Generation assets used for the Heritage Contract is being proposed at this time.

In its November 21, 2002 decision the BCUC allowed BC Gas an after-income tax return on equity of 9.42% for 2003. That rate has been used in this proposal. This after-income tax return is then "grossed-up" to a "pre-income tax basis" by applying the effective income tax rate of BC Gas. The effective income tax rate approved for BC Gas in its 2003 Revenue Requirement decision was 34.24%. Thus the pre-income tax return is:

$$9.42\% \ / \ (1 - 34.24\%) = 14.33\%$$

BC Hydro's equity has been allocated to its various businesses on a pro-rata basis based on the capital assets assigned to each business. The amount of equity allocated to the Heritage Resources for fiscal 2004 was $1,073 million.

The $1,073 million is the sum of deferred revenue from the Skagit Valley Treaty of $279 million, $202 million of deferred charges from the Columbia River Treaty and an allocation of BC Hydro retained earnings of $592 million, calculated in conformity with Special Direction No. 8. Thus the required return on equity for F2004 is:

$$\$1{,}073 \text{ million} \times 14.33\% = \$154 \text{ million}$$

For subsequent fiscal years the return on equity is calculated on the same basis, revised for changes in the amount of Heritage Contract equity and the pre-income tax rate of return of BC Gas.

DIRECT TESTIMONY OF KEN SPAFFORD

Q1. *Please state your name and present position.*

A. My name is Kenneth Ray Spafford. I hold the position of Principal Engineer with the Resource Management group of B.C Hydro's Generation line of business.

Q2. *How long have you held that position?*

A. For approximately 8 years.

Q3. *What were your previous positions with BC Hydro?*

A. I previously have held the positions of Manager, Resource Planning; Manager, Resource Optimization: and a number of engineering positions within the business units responsible for resource planning and acquisition.

Q4. *What positions did you hold prior to joining BC Hydro and with whom?*

A. I started with BC Hydro immediately after graduation from university.

Q5. *What are your professional qualifications?*

A. I graduated from the University of British Columbia in 1973 with a Bachelor of Applied Science degree and am a registered professional engineer.

Q6. *Have you previously testified before this Commission or its predecessors?*

A. Yes, I testified at the following hearings:

- 1991 Energy Removal Certificate renewal application, specifically to address issues related to the supply and demand balance and the estimates of surplus capability;
- 1992 Rate Design Hearing, specifically to address issues related to the cost of new supply and the impact of the proposed rates on BC Hydro's Electricity Plan;
- 1993 and 1994 Revenue Requirements hearings, specifically to address issues related to BC Hydro's integrated resource plan;
- 1994 Kemano Completion Project Review, specifically to address issues related to purchase agreements between BC Hydro and Alcan; and
- 1995 Electricity Market Structure Review, specifically to provide information on reservoir system optimization.

Q7. *What role did you play in the development of this Application?*

A. I contributed to the development of the information on the Heritage Resource capability and participated in the overall drafting of the application.

Q8. *Are there sections of the Application for which you assumed particular responsibility?*

A. Yes. I will be speaking to the following sections of the Heritage Contract proposal: Sections 2.1, 3.1, 3.2 and 3.5.

Q9. *Does that complete your testimony?*

A. Yes.

DIRECT TESTIMONY OF CHRIS O'RILEY

Q1. *Please state your name and present position.*

A. My name is Chris O'Riley. I am Powerex Risk Manager. I also have a role as a Corporate Risk Consultant in BC Hydro, reporting to the Chief Financial Officer.

Q2. *How long have you held that position?*

A. I've been the Powerex Risk Manager since May 1999. I've held the Corporate consultancy position since fall 2002.

Q3. *What were your previous positions with Powerex and BC Hydro?*

A. I previously worked as a Portfolio Manager at Powerex, an account manager and analyst in BC Hydro Customer Services, and as a Telecontrol line manager and Engineer in Training with BC Hydro Production.

Q4. *What positions did you hold prior to joining BC Hydro and with whom?*

A. I joined BC Hydro in 1990, after graduating from UBC.

Q5. *What are your professional qualifications?*

A. I have a Bachelor of Applied Science degree from the University of British Columbia (1990) and a Masters Degree in Business Administration from the University of Western Ontario (1995). In 1993 I became a registered professional engineer in British Columbia.

Q6. *Have you previously testified before this Commission or its predecessors?*

A. No.

Q7. *What role did you play in the development of this Application?*

A. I worked on the team developing BC Hydro's proposal.

Q8. *Are there sections of the Application for which you assumed particular responsibility?*

A. Yes. I will be speaking to the following section of the Heritage Contract proposal: Section 3.3.

Q9. *Does that complete your testimony?*

A. Yes.

DIRECT TESTIMONY OF DOUG LITTLE

Q1. *Please state your name and present position.*

A. My name is Douglas Little. I am Vice President, Marketing and Trade Policy at Powerex Corp.

Q2. *How long have you held that position?*

A. I have held my present position since October 2002.

Q3. *What were your previous positions with Powerex or BC Hydro?*

A. I joined BC Hydro in 1990 and worked in the rate design, policy development and inter-utility contracts areas. In 1993 I moved to Powerex to head up its regulatory group and was appointed Vice President, Trade Policy and Development in October 1998.

Q4. *What positions did you hold prior to joining BC Hydro and with whom?*

A. Prior to returning to graduate school I worked for three years in the Engineering Department of an insurance risk management consulting firm.

Q5. *What are your professional qualifications?*

A. I have a Bachelor of Applied Science Degree in Civil Engineering and Masters Degree in Business Administration, both from the University of British Columbia.

Q6. *Have you previously testified before this Commission or its predecessors?*

A. Yes. I testified in the BC Hydro Wholesale Transmission Service Application Hearings in 1997, and the WKP 3808/PPA hearing in 1993. I have also testified in regulatory proceedings in Alberta and with the Bonneville Power Administration.

Q7. *What role did you play in the development of this Application?*

A. I was a member of the Oversight Committee responsible for overseeing the development of this Application.

Q8. *Are there sections of the Application for which you assumed particular responsibility?*

A. Yes. I will be speaking to section 3.4 of the Heritage Contract proposal.

Q9. *Does that complete your testimony?*

A. Yes.

DIRECT TESTIMONY OF CAM LUSZTIG

Q1. *Please state your name and present position.*

A. My name is Cam Lusztig. I am Senior Regulatory Advisor with BC Hydro.

Q2. *How long have you held that position?*

A. 3 years.

Q3. *What were your previous positions with BC Hydro?*

A. I have held no other positions at BC Hydro.

Q4. *What positions did you hold prior to joining BC Hydro and with whom?*

A. I was Senior Economist at both the BC Utilities Commission and at the BC Central Credit Union.

Q5. *What are your professional qualifications?*

A. I have an undergraduate degree in Economics from the University of British Columbia and a Masters Degree in Business Administration from the University of Western Ontario.

Q6. *Have you previously testified before this Commission or its predecessors?*

A. Yes, in respect of BC Hydro's application for IPP Access on the Distribution System.

Q7. *What role did you play in the development of this Application?*

A. I worked on the team developing BC Hydro's proposal. In particular, I helped to develop the mechanisms to allocate the benefits of the heritage resources to ratepayers.

Q8. *Are there sections of the Application for which you assumed particular responsibility?*

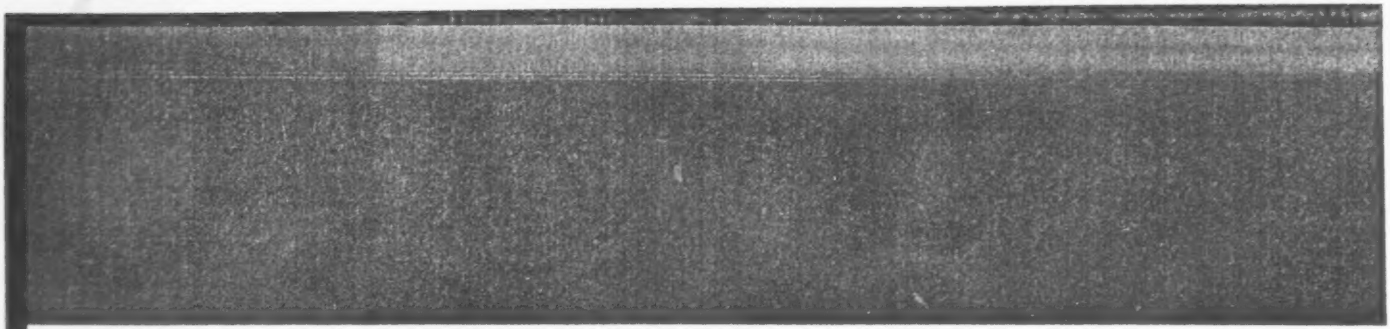
A. Yes. I will be speaking to the following sections of the Heritage Contract proposal: Sections 2.2, 3.5 and 3.6.

Q9. *Does that complete your testimony?*

A. Yes.

DIRECT TESTIMONY OF TONY MORRIS

Q1.	*Please state your name and present position.*
A.	My name is Tony Morris. I am Group Controller, Generation line of business, BC Hydro.
Q2.	*How long have you held that position?*
A.	Since March 2002.
Q3.	*What were your previous positions with BC Hydro?*
A.	Since joining BC Hydro in September 1989 I have held the following positions: • Management positions within the Corporate Controllers Division 1989-1994 • Corporate Controller 1994-1997 • Group Controller (Marketing & Customer Service; Executive Operations: Operations) 1997-2002
Q4.	*What positions did you hold prior to joining BC Hydro and with whom?*
A.	Prior to joining BC Hydro I was employed by Price Waterhouse from 1974 -1989. My last position with them was a Director in the Business Valuation and Litigation Support Group.
Q5.	*What are your professional qualifications?*
A.	I am a chartered accountant (1973) and a chartered business valuator (1989).
Q6.	*Have you previously testified before this Commission or its predecessors?*
A.	Yes, in BC Hydro's most recent revenue requirements application (1994).
Q7.	*What role did you play in the development of this Application?*
A.	I had overall responsibility for the financial information in the application
Q8.	*Are there sections of the Application for which you assumed particular responsibility?*
A.	Yes. I will be speaking to the following section of the Heritage Contract proposal: Section 3.7 and Appendix F.
Q9.	*Does that complete your testimony?*
A.	Yes.



IN THE MATTER OF

The Utilities Commission Act (the Act)

and

A Request of the Lieutenant Governor in Council
of the Province of British Columbia
pursuant to Section 5(1) of the Act to the
British Columbia Utilities Commission (the Commission)
to Inquire into and Advise on a
Heritage Contract for BC Hydro's Existing Generation Resources,
Stepped Rates and Transmission Access

and

Terms of Reference Issued March 25, 2003 Pursuant to Order in Council 0253 and
Section 5(2) of the Act (Terms of Reference)

and

Order G-23-03 of the Commission Directing BC Hydro to File a Proposal
Regarding a Heritage Contract,
Stepped Rates and Transmission Access

A PROPOSAL BY THE BRITISH COLUMBIA HYDRO AND POWER AUTHORITY REGARDING A HERITAGE CONTRACT, STEPPED RATES AND ACCESS PRINCIPLES

VOLUME 2 OF 2

APRIL 30, 2003

Energy Plan
IMPLEMENTATION

BChydro

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- I) Curricula Vitae of Stepped Rate Design Report Authors

Appendix B: BC Hydro Information Session and Workshop on Stepped Rates and Access Principles (dated March 5, 2003)

Appendix C: Summary of BC Hydro's March 5 Workshop on Stepped Rates & Access Principles (dated March 14, 2003)

Appendix D: Comments from Interested Parties Regarding Stepped Rates
- i) Cloudworks Energy Inc. (dated March 5, 2003)
- ii) Joint Industry Electricity Steering Committee (dated March 11, 2003)
- iii) Saskatchewan Wheat Pool (dated March 26, 2003)
- iv) Leader Mining International Inc. (dated March 28, 2003)
- v) Joint Industry Electricity Steering Committee (dated April 1, 2003)
- vi) Aquila Networks Canada (dated April 24, 2003)
- vii) Corporation of the City of New Westminster (dated April 25, 2003)

1 INTRODUCTION

1.1 *Context of the Inquiry*

This proposal is the second of two volumes that, together, have been filed by BC Hydro in response to Commission Order No. G-23-03. Volume 1 deals with all aspects of the Heritage Contract, and contains BC Hydro's proposal with respect to paragraph 3 of the Terms of Reference. This volume covers paragraph 4 of the Terms of Reference, which asks the Commission to make recommendations concerning the design of stepped rates for BC Hydro's transmission voltage customers. Paragraph 4 of the Terms of Reference states:

> "The Commission shall make specific Recommendations relating to any changes it believes are desirable in the rates of transmission voltage customers to accomplish the objectives set out in the Energy Plan, including:
>
> (a) The terms and conditions that should govern existing and new large industrial or transmission rate customers' access to transmission for the purposes of acquiring power from other energy suppliers' generation;
>
> (b) The detailed provisions of new stepped rate schedules as more fully described in the Energy Plan, including load aggregation by a customer with facilities at more than one location; and
>
> (c) The principles which should govern the terms and conditions under which large industrial or transmission rate customers wishing to obtain generation from alternate suppliers may decline to obtain service from BC Hydro or may apply to obtain service from BC Hydro thereafter."

The Energy Plan describes the new BC Hydro rate structures for transmission voltage customers as follows:

> **"Policy Action #14 (new): Under new rate structures, large electricity consumers will be able to choose a supplier other than the local distributor.**
>
> New stepped pricing...will provide an incentive for large industrial or transmission rate customers to purchase from IPPs, or to self generate, when they can do so less expensively than the utility's cost of new supply. These larger customers will be able to meet all or a portion of their consumption from private generation. This policy change introduces retail competition for large BC Hydro customers."

> **"Policy Action #21 (new): New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.**
>
> The BC Utilities Commission will conduct a hearing to develop new stepped and time-of-use pricing for BC Hydro's industrial and large commercial customers. As a principle, for stepped rates, the last block of energy consumed should reflect the cost of new supply. This will encourage these customers to meet part of their electricity needs through conservation and energy efficiency, or from other sources (self-generation or IPP purchases), where they can do so cost-effectively. To keep rates low overall, the stepped rate structure will be revenue-neutral... Time-of-use rates will encourage customers who can manage the timing of their electricity use to shift consumption to low-priced off-peak periods."

1.2 *Overview of Stepped Rates*

BC Hydro believes that stepped rates, as contemplated in paragraph 4(b) of the Terms of Reference, provide an opportunity to encourage its customers and privately owned suppliers to make new investments that are beneficial to the province, while preserving the benefits of low, embedded cost rates. In addition, the stepped rate design will enable BC Hydro customers and Independent Power Producers (IPPs) to make mutually beneficial direct access arrangements.

A stepped rate design will feature different prices for different blocks of energy consumption. For example, in each billing period energy consumption up to "X" MWh is priced at a "Tier 1" rate, while consumption above "X" MWh is priced at a "Tier 2" rate. When suitably designed, the Tier 1 and Tier 2 rates and the cut-off point between them are parameters that can help achieve the various policy objectives in the Energy Plan. On the other hand, if the parameters of the stepped rate are not designed carefully, there could be undesirable incentives, which are discussed below.

2 PRINCIPLES FOR BC HYDRO STEPPED RATE DESIGN

To assist in the development of the proposal for stepped rates, BC Hydro retained the services of Energy and Environmental Economics, Inc. (E3). The report prepared by E3 is discussed in more detail below and reproduced in its entirety at Tab A of this volume. Early in discussions with E3, it became apparent that a stepped rate proposal should adhere to some basic principles. Failure to adhere to these principles will, in BC Hydro's view, cause undesirable and potentially substantial cost shifting between customers. The principles are:

(1) The stepped rate should be a mandatory tariff. The principle is that new growth above a customer's historic consumption would be supplied at the "cost of new supply," rather than at existing embedded cost-based rates or a blend of old and new costs. At the same time, BC Hydro needs to carefully balance the objectives of providing the proper price signals with offering comparable terms to both new and existing customers who increase their consumption.

If Schedule 1821 is preserved as the default tariff, customers contemplating growth would elect to be served at a rate based on the rolled-in cost of BC Hydro's generation resources, rather than at rates consistent with "the utility's cost of new supply" as described in Policy Actions #14 and #21.

Preserving the option of serving load at 1821 rates would also limit the extent of "retail competition for large BC Hydro customers" (Policy Action #14) because new supplies are unlikely to be cost-competitive when compared to BC Hydro's existing hydro generation. Finally, it might give industrial customers who are working with wholesale marketers the ability to purchase power at a low embedded cost-based price and resell it at higher market-based prices. This would increase rates to all non-participating customers of BC Hydro.

(2) The stepped rate should be "revenue or bill neutral" at historical consumption levels. If the stepped rate customer does not change its usage relative to its past consumption, the customer's bill should remain unchanged after the

implementation of the stepped rate. This assures that even though the stepped rate is a mandatory tariff, the benefits of low-cost power will continue for all customers.

(3) The stepped rate should be "margin neutral" at all consumption levels. The stepped rate should provide incentives for changes in consumption that do not result in costs or risks being shifted to other customers. In other words, the stepped rate should also be "margin neutral" for BC Hydro, where margin is revenue less cost, adjusted for risk. This is ensured by "incremental" cost pricing. Under incremental pricing, bill credits granted to customers for their energy savings do not exceed BC Hydro's risk-adjusted value of the saved energy, and bills sent for additional growth cover BC Hydro's incremental costs and risks of acquiring new supply. This is also a change from the historical practice of "rolled in" pricing to "incremental" pricing for consumption changes above or below historic consumption levels.

In addition, there are aspects of the Heritage Contract provisions of the Energy Plan and Terms of Reference that BC Hydro believes constrain the proposal that can reasonably be put forward in this volume. In particular, BC Hydro believes that the Heritage Contract – not the stepped rate design – is the mechanism by which the value of the low-cost and flexible heritage assets is delivered to ratepayers.

Within its Heritage Contract proposal (see Volume 1), BC Hydro has described a compact that allocates the value of heritage assets (those plants and obligations listed in Schedule A of the Terms of Reference) to Heritage Beneficiaries (the *classes* of customers listed in Schedule B of the Terms of Reference). The Energy Plan and the Terms of Reference require this approach, as discussed in detail in Volume 1.

Structuring the Heritage Contract this way leaves the Commission with the discretion to allocate the costs of the electricity in the Heritage Contract among the classes of customers listed in Schedule B of the Terms of Reference. BC Hydro expects that the Commission will do this on a pro-rata basis, by customer class, as part of BC Hydro's upcoming revenue requirements process. BC Hydro also expects that the Commission may consider alternative inter-class allocations as part of an eventual rate design hearing.

However, BC Hydro does not believe that the Energy Plan intended for Heritage Beneficiaries to be identified individually on a customer-specific basis, nor did it intend for rate designs to have the effect of assigning heritage value directly to individual customers. As such, the proposals contained in this volume reject any such direct assignment.

Distinguishing between the assignment of heritage benefit by class and by customer is critical. If heritage value is assigned directly to a customer (based on historical usage, for example), it suggests a right of ownership. This can provide customers with the incentive to sell their "slice" of the system, while cutting back on production or quitting business altogether. In this way, these customers can effectively capture the heritage value for themselves and leave it unavailable to drive benefits for all British Columbians.

Stepped rate designs that adhere to the above guiding principles promote changes in consumption or investments that are cost-effective from the perspective of all BC Hydro's customers. The designs ensure that no individual customers are made worse off by the action of another existing customer.

As long as the designs do not shift historical costs among customers and rely on incremental costing to bring about incremental changes in consumption, there is no need to focus the outcome of this inquiry on a single "best" design. BC Hydro could offer different tariffs for customers who wanted a longer term, fixed price design and those who wanted to take advantage of more frequently updated market price signals.

Some designs are more flexible than others and would allow BC Hydro to offer both a single long-term multi-year rate and a rate that varies by time of use period and month. There are other designs that are more simple and more certain, but they provide less flexibility for customers and require complicated access rules to ensure that non-participants (industrial customers whose consumption does not change and customers in other rate classes) are not harmed.

BC Hydro believes it is premature to design the rate now without further consultations because many aspects of the design, and the options it should include, will depend upon customer preferences that are not yet fully understood.

BC Hydro acknowledges that some interested parties appear ready to identify the basic characteristics of the stepped rate design now. In particular, BC Hydro received a letter dated March 11, 2003 from the Joint Industry Electricity Steering Committee (JIESC). In their letter, the JIESC commented on the information presented at the BC Hydro Rate Design Workshop, discussed below, and presented a stepped rate design. The JIESC letter is found at Tab D(ii) of this volume.

Ultimately, a form of phased-in implementation, starting with a relatively simple design and adding more complex options as customer needs and experience develop, may be the most prudent way to implement a new structure in British Columbia. A design could be initially implemented that establishes a basic framework, and subsequently allows for additional refinements to be added based on customer demand. While BC Hydro believes that design requires significant stakeholder input before being finalized, certain conclusions can be reached now based on the work of E3. Before identifying those conclusions, a brief discussion of E3's report is necessary.

3 ENERGY AND ENVIRONMENTAL ECONOMICS REPORT

In an effort to provide the broadest possible scope of input to the Commission as it considers the issues raised by paragraph 4 of the Terms of Reference, BC Hydro hired E3 to provide a report that sets out a range of stepped rate design options and issues. E3 was provided with the principles identified in Section 2, above, and asked to develop alternative rate forms to serve them. With the assistance of the March 5, 2003 Workshop, discussed below, and subsequent written commentary of stakeholders submitted to BC Hydro, E3 prepared an overall review of the alternatives to stepped rate design. E3's resulting report, "Stepped Rate Design Report", is found at Tab A of this volume. The curricula vitae of the authors of the report are found at Tab A(i).

E3 was not asked to and did not present a single complete rate design that emerges as the obvious best choice. Each of the designs presented in the report is suited to one or more of the rate design objectives. The choice among the designs ultimately requires a ranking of the relative importance of the stepped rate objectives, including the objectives in the Energy Plan.

The Energy Plan's objectives and constraints for the stepped rate design are described in E3's report, along with their expected implications for ratepayers and the utility. The analysis presented is intended to assist all stakeholders to determine for themselves how the objectives of the Energy Plan and their own interests will be served under each design.

4 BC HYDRO'S CONCLUSIONS WITH RESPECT TO SOME ASPECTS OF STEPPED RATE DESIGN AND IMPLEMENTATION MECHANISMS

Based on the analysis performed by E3, BC Hydro has reached some conclusions with respect to certain aspects of rate design, but appreciates that much more work with stakeholders needs to occur before a detailed design can be developed. Indeed, in one important area, the principles that should govern access to service from BC Hydro, BC Hydro has reached the very firm conclusion that development of access rules must await identification of the specific rate design to which the rules of access will attach. On the other hand, BC Hydro has concluded that the objectives of the methodology for determining base load consumption for each customer (customer baseline or "CBL") can be determined now. However, further stakeholder input is necessary to advance beyond high-level principles and develop the specific mechanisms to determine CBLs. While many aspects of the stepped rate design will be clarified after further consultations, the shopping credit mechanism appears to be the preferred method of implementation whatever rate design is ultimately chosen. BC Hydro's position in connection with each of these issues is presented in the balance of this section.

4.1 *Access Principles*

The E3 report identifies some significant risks associated with the implementation of a stepped rate design. It groups these risks into three categories:

(1) Risks arising from fluctuating markets;
(2) Risks arising from inaccurate setting of price signals; and
(3) Risks arising from providing customers with the ability to switch suppliers.

The worst-case quantification analysis performed by E3 demonstrates that unless these risks can be successfully mitigated, the potential costs of the stepped rate overwhelm its advantages. Accordingly, the incorporation of appropriate measures to limit risk will be a key component of any desirable rate design.

The discussion of risk factors in the E3 report makes clear that a wide variety of mitigative measures are available to deal with risk, some through rate design and others through principles that govern access to those rates. Thus, provisions dealing with adjustments to CBLs may mitigate some sorts of risks, while provisions governing the rights of customers to demand supply from BC Hydro when they have chosen alternative supply sources may deal with others. This suggests that the choice of access principles is integrally linked with the choice of rate design. Until the design is known, it is not possible to determine appropriate access principles.

In light of these considerations, BC Hydro has not sought to identify access principles in this proposal. As consensus develops around the design of the stepped rate, BC Hydro will evoke access principles to suit and expects them to be fully considered through the consultation process described in Section 5.2.

4.2 *Customer Baseline*

BC Hydro has concluded that, as a matter of principle, CBLs should be developed for each industrial customer that reflect average economic conditions on an industry-by-industry or facility-by-facility basis. However, beyond this general objective, the E3 report describes some of the difficulties associated with the derivation of each customer's CBL, which would be an integral part of either the shopping credit or two-part designs. BC Hydro and its customers have some experience with developing CBLs in connection with BC Hydro's Real-Time Pricing (RTP) rates (Schedule 1848). There is no question that derivation of CBLs will raise many challenging issues and no one approach is likely to please all stakeholders. Compounding the challenges of CBL derivation is the issue of "load aggregation", about which the Commission was directed to make recommendations in paragraph 4(b) of the Terms of Reference. Actual CBLs will inevitably be the product of customer-by-customer discussions, possibly with the Commission's review and approval.

For this reason, BC Hydro believes that the specific mechanism for developing CBLs for individual customers or customer groups should be the subject of further stakeholder input.

A particularly difficult issue in connection with CBL derivation is the treatment of new load. Should a customer's CBL change with its load over time and how should the load of new customers be treated?

As elaborated in Volume 1 dealing with the Heritage Contract, BC Hydro does not believe the Energy Plan contemplates vintaging access to the low embedded cost of BC Hydro's existing generating resources. Thus, new customers, as well as old, should have access to the benefits of low-cost generation. This suggests setting CBLs for new customers based on "normal" consumption. Any other approach would favour old over new consumption and defeat economic development objectives by imposing significantly higher costs on new investment than old.

On the other hand, from a fairness point of view, it is difficult to see why new facilities in an existing plant should be treated differently than a new plant. Parity could only be accomplished by permitting existing customers a new CBL if they increased consumption because of increased production at their facility. This would add great complexity to the rate design and raise difficult questions with respect to identifying what conditions did and did not qualify a customer for a new CBL.

The difficulties associated with new load illustrate an inherent tension that will be introduced by any stepped rate design that charges higher rates at the margin. Higher marginal rates will tend to discourage energy consumption, thus, discouraging energy intensive development. In this sense, economic development objectives may conflict with the promotion of conservation and the maintenance of low-cost energy for the load that is already here.

The stakeholder consultation process should help clarify the issues, but is unlikely to resolve the conflict between those who give different weight to the value of economic development, conservation or even-handedness in rate design. Even if consensus were to develop amongst existing interests, government would need to consider the interests of potential new customers not represented in this process. In these circumstances, the Commission can best fulfill its role in this inquiry by clearly identifying the public policy tradeoffs it has made in arriving at its recommendations. Balancing these competing objectives is a matter of provincial policy.

4.3 *Shopping Credit vs. Two-Part Rate*

E3's report distinguishes between two mechanisms to assist in the implementation of any stepped rate design. The first is a two-part rate with a portion of a customer's normal existing consumption being charged at one rate and the remainder at another. The second is the "shopping credit" mechanism in which all normal existing consumption is charged at one rate, but customers are given a credit or charged for variations from normal consumption based on a different rate or rates. BC Hydro has concluded the "shopping credit" is the preferable mechanism for introducing any of the potential rate designs that would be consistent with the policy objectives the stepped rate is intended to serve.

The shopping credit allows BC Hydro to offer direct access under a retail tariff without undertaking a complete unbundling of retail rates. The shopping credit constitutes a "price to beat" for third party suppliers, or investment in demand-side management (DSM) or self-generation.

This mechanism has a number of advantages over a strict two-part rate design.

First, the shopping credit mechanism is more flexible than a two-part rate in that the terms of the credit can take into account a broad spectrum of policy preferences and can be modified to take into account unforeseen circumstances that require immediate action. It lends itself to phased-in implementation, which is desirable for a relatively untested rate form. If, notwithstanding the design efforts of all participants, the final rate design caused undesirable behaviours by market participants, the terms and conditions of ongoing access to the credit could be adjusted more easily than undertaking a wholesale redesign of a two-part rate.

Second, the shopping credit mechanism can be used to give customers greater flexibility by allowing them to pursue direct access for up to their entire loads, regardless of where the Tier 1 cut-off point is placed. A stepped rate without a shopping credit, for all intents and purposes, allows direct access only for that portion of load served at the Tier 2 rate.

Third, the E3 report makes clear that determining the manner in which retail industrial customers should obtain access to transmission is potentially very complex. Section 4(a) of the Terms of Reference provides that:

> "The Commission shall make specific Recommendations relating to any changes it believes are desirable in the rates of transmission voltage customers to accomplish the objectives set out in the Energy Plan, including:
>
> (a) The terms and conditions that should govern existing and new large industrial or transmission rate customers' access to transmission for the purposes of acquiring power from other energy suppliers' generation;"

Further, the Energy Plan provides the following specific policy actions:

> **"Policy Action #15 (new): The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.**
> A new publicly owned entity, BC Hydro Transmission Corporation, will be responsible for planning, operating, and managing BC Hydro's transmission system."
>
> **"Policy Action #16 (new): The BC Utilities Commission will determine the terms and rates for this new transmission entity.**
> The BC Utilities Commission will review and approve wholesale transmission rates. In an initial hearing, the Commission will consider issues such as the allocation of costs between generation and transmission, and exit and entry fees for large customers who leave the BC Hydro system (under the new rate structure). Once the initial rates have been determined, future rate changes will also be reviewed and approved by the Commission."

The objective of transferring responsibility for the operation of BC Hydro's transmission system to a new corporation that will have responsibility, amongst other things, to design transmission rates, makes it undesirable to adopt a stepped rate design that would necessitate immediate redesign of the Wholesale Transmission Service (WTS) tariff. It is not expected that the Commission will determine the terms and rates for the new transmission entity until 2004/2005, and a redesign of the WTS tariff should only take place, if at all, at that time.

BC Hydro believes that all of these factors point in the same direction. The shopping credit mechanism permits a clear identification of risks and will accommodate appropriate risk mitigation factors once its particulars are known. The shopping credit mechanism can be phased in in a number of ways as discussed in the E3 report, and it may obviate the need to use WTS for the provision of direct access. For these reasons, BC Hydro has concluded that a shopping credit mechanism is the preferred way to implement a stepped rate design.

If the government, based on a Commission recommendation, determines that the shopping credit mechanism is appropriate, a Commission Order is all that would be required to make it available to transmission voltage customers.

5 STEPPED RATE DESIGN AND ACCESS PRINCIPLES PROCESS

As was emphasized above, multiple forms of the stepped rate design can be successfully implemented. Some designs offer more flexibility for customers, while others provide simplicity and certainty but require complicated access rules. E3 concludes in its report that no single rate design emerges as the obvious best choice. The choice among the designs ultimately requires a ranking by stakeholders of the relative importance of the stepped rate objectives, including, in particular, the objectives in the Energy Plan.

5.1 *BC Hydro Rate Design Workshop*

BC Hydro has engaged in considerable public consultation over the course of developing the stepped rate portion of this proposal. This consultation included a workshop on Stepped Rates and Access Principles held on March 5, 2003, to which over 300 transmission-voltage customers, independent power producers and other interested parties were invited. The goals of the workshop were to: present a number of rate design choices that meet the goals and objectives of the Energy Plan; identify some key implementation issues; and solicit input from customers and other interested parties to assist BC Hydro to frame its proposal on stepped rates and access principles. A copy of the March 5, 2003 workshop presentation titled "BC Hydro Information Session and Workshop on Stepped Rates and Access Principles" is found at Tab B of this volume, and a copy of the workshop summary titled "Summary of BC Hydro's March 5 Workshop on Stepped Rates & Access Principles" is found at Tab C.

BC Hydro has also engaged in on-going consultation with affected customers and other stakeholders. Copies of written comments on stepped rates that BC Hydro received from stakeholders after the workshop are found at Tab D.

5.2 *Further Process*

As discussed above, this proposal suggests clear boundaries for acceptable designs, and focuses on the design elements within those boundaries. There is substantial work yet to be done, and much of it involves trade-offs where there is no "right" answer.

BC Hydro agrees with the Commission that "not all issues raised by the Terms of Reference may need to be considered in the public hearing phase for the Inquiry." In fact, BC Hydro believes that the limited conclusions it has reached based on the E3 report are ones that would benefit from discussion with all of its stakeholders. The initial consultative workshop was well-attended and generally constructive. A continuation of that process so that all stakeholders fully understand the analysis of E3 will permit everyone to either accept or reject the general preference that BC Hydro has expressed for the shopping credit approach.

BC Hydro proposes to hold one or more additional workshops on this issue through May and June 2003 so as to be able to report back to the Commission at the July 7, 2003 workshop. This would be in addition to the Commission-sponsored workshop focusing on the Heritage Contract planned for May 13, 2003.

BC Hydro is firmly of the view that unless differences between stakeholders become completely entrenched, consultative processes are better suited to dealing with the complexities of the stepped rate design than formal hearing processes.

Accordingly, if high-level consensus exists among stakeholders by early July 2003, BC Hydro would intend to continue the consultation process and, to ensure that this process remains consistent with the Commission's need to file its October 17 report to government, BC Hydro would submit a second report to the Commission no later than September 15, describing the state of the new rate's development at that time.

If at any time it were to become clear that a written hearing or other process would advance development or all or some part of the new rate, the Commission could direct such a process. In the event of such a hearing, BC Hydro would then include its final report relating to the stepped rate proposal as part of its final argument in its August 2003 submission and intervenors could comment on the report, as necessary, in their written submissions.

6 CONCLUSIONS / ACTIONS NEEDED FROM GOVERNMENT TO IMPLEMENT A STEPPED RATE STRUCTURE AND RETAIL ACCESS

It is not possible to identify the steps government need take in connection with stepped rates at this time. However, as a general statement, BC Hydro believes the Commission should recommend that if government wishes to require the adoption of the stepped rate, it should:

- issue a special direction to the Commission concerning the establishment of rates for transmission voltage customers that adhere to those of the Commission's recommendations or rate changes that the government accepts; and
- if it determines that direct transmission access through the use of the WTS tariff is needed, issue a special direction requiring the Commission to provide for retail access to WTS by transmission voltage customers served under the stepped rate design.

4/28/2003

Energy and Environmental Economics, Inc.

Stepped Rate Design Report

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1 Introduction

1.1 Background

British Columbia announced a new energy plan for the province on November 25, 2002, which is designed to build on the province's energy strengths, in particular its abundant natural resources and low electricity prices, to help revitalize the economy and create jobs in an environmentally responsible way. The document, entitled "Energy for Our Future: A Plan for BC" (Energy Plan), has four key objectives:

- Low electricity rates and public ownership of BC Hydro;
- Secure, reliable supply of energy;
- More private sector opportunities;
- Environmental responsibility and no nuclear power sources.

Under the Energy Plan, new legislation will preserve the value of existing low-cost generation (known as "heritage energy") for current and future BC Hydro ratepayers, according to the terms set by the BC Utilities Commission (BCUC). BC Hydro's existing generation, transmission and distribution assets will continue to be publicly owned to protect ratepayers and taxpayers, but BC Hydro will outsource services where it can reduce costs without affecting the quality of service. BC Hydro's rates have not changed since 1993, and the most recent rate freeze ended on March 31, 2003. The BCUC will hold a revenue requirement hearing in early 2004 to review BC Hydro's costs.

To increase opportunities for the private sector, encourage aggressive conservation and energy efficiency, and promote alternative energy development, the

Energy Plan recommends the implementation of stepped and time-of-use electricity rates for industrial customers. Stepped rates charge consumers a higher price for electricity at higher levels of consumption, increasing the incentives for conservation and efficiency without raising the average electricity rate (based on a constant level of consumption). Typically, different rates are set for different "tiers" of consumption, with Tier 1 being the lowest rate and Tier 2 being a higher rate reflective of the cost of new supply.

Time-of-use rates charge a different price for power depending on the time of day or season to encourage consumers that are flexible with the timing of their electricity use to shift consumption away from higher priced periods of peak demand. Both methods minimize the need for new power generation resources to be developed in the province, help protect the environment, and can save ratepayers money. The BCUC has already approved time-of-use pilots for some of the larger BC Hydro customers. Given the administrative costs of rate design and the metering investment required for time-of-use rates, these rate structures tend to be more feasible for large customers.

This report presents a family of stepped rate designs for large industrial customers that can be used to meet the objectives described in the Energy Plan. The designs range from the simple (e.g., 90 percent of a customer's historical consumption billed at a low rate and 10 percent at a higher rate based on the cost of new supply), to flexible designs where customers pay market prices for all incremental changes in consumption beyond a baseline level of usage. The report describes the characteristics of each of these designs and their ability to meet the objectives of the Energy Plan. Desirable characteristics include simplicity, economic efficiency, cost-shifting potential, and BC Hydro's ability to continue to collect the industrial class revenue requirement.

The primary authors of the report are Ren Orans, CK Woo, and Arne Olson from the consulting firm of Energy and Environmental Economics, Inc. (E3). E3 has extensive rate design and electricity market restructuring experience in both Canada and in the U.S. Dr. Orans testified before the BCUC for BC Hydro in the Electricity Market Structure Review (1995) and in their last two wholesale transmission rate cases (1995, 1997). Dr. Woo testified before the BCUC for BC Hydro in support of its two-part RTP rate during the last time that the Company conducted extensive consultations with customers on industrial service options (1997). Mr. Olson has recently represented BC Hydro in its efforts to participate in RTO West. The authors' CVs are contained in Attachment 1 of this report.

This team was hired in February of 2003 to work closely with BC Hydro's rate design staff to define a range of stepped rate structures that benefit BC Hydro's customers and can be readily implemented within the rate and tariff structures already in place.

1.2 BC Hydro's Recommended Stepped Rate Guidelines

1.2.1 Energy Plan Policy Actions related to Stepped Rate

Although this team was responsible for developing the key findings and recommendations in this report, its scope of analysis was defined by guidelines recommended by BC Hydro's management. These guidelines are based on BC Hydro's interpretation of the policy actions described in the in the Energy Plan. The Energy Plan (p.7) states a series of policy actions and their implied goals that are important and relevant to the stepped rate designs examined in this report:

- **Policy Action #1**. A legislated heritage contract will preserve the benefits of BC Hydro's existing generation.
- **Policy Action #2**. BC Hydro ratepayers will continue to benefit from electricity trade.
- **Policy Action #5**. The BCUC will once again regulate BC Hydro rates.
- **Policy Action #9**. Electricity distributors will acquire new supply on a least-cost basis, with regulatory oversight from the BCUC.
- **Policy Action #13**. The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.
- **Policy Action #14**. Under new rate structures, large electricity consumers will be able to choose a supplier other than the local distributor.
- **Policy Action #16**. The BCUC will determine the terms and rates of the BC Hydro Transmission Company.
- **Policy Action #21**. New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.

1.2.2 Stepped Rate Design Guidelines

There are a wide variety of stepped rate designs that can be used to implement these policy actions. As long as the stepped rate designs can be implemented without shifting costs or risks to BC Hydro's other customers, the process of choosing among designs should involve a high degree of interaction among large industrial customers, the BCUC, independent power producers (IPPs) and the Government. To facilitate the process of developing mutually beneficial stepped rate designs, BC Hydro recommends that the Commission adopt a set of rate design guidelines. BC Hydro has used the three guidelines below to define the designs considered in this report.

1. The stepped rate should be a mandatory tariff. The principle is that new growth above a customer's historic consumption would be supplied at the "cost of new supply," rather than at existing embedded cost-based rates or a blend of old and new costs. At the same time, BC Hydro needs to carefully balance the objectives of providing the proper price signals with offering comparable terms to both new and existing customers who increase their consumption.

   If Schedule 1821 is preserved as the default tariff, customers contemplating growth would elect to be served at a rate based on the rolled-in cost of BC Hydro's generation resources, rather than at rates consistent with "the utility's cost of new supply" as described in Policy Actions #14 and #21.

   Preserving the option of serving load at 1821 rates would also limit the extent of "retail competition for large BC Hydro customers" (Policy Action #14) because new supplies are unlikely to be cost-competitive when compared to BC Hydro's existing hydro generation. Finally, it might give industrial customers who are working with wholesale marketers the ability to purchase power at a low embedded cost-based price and resell it at higher market-based prices. This would increase rates to all non-participating customers of BC Hydro.

2. The stepped rate should be "revenue or bill neutral" at historical consumption levels. If the stepped rate customer does not change its usage relative to its past consumption, the customer's bill should remain unchanged after the implementation of the stepped rate. This assures that even though the stepped rate is a mandatory tariff, the benefits of low-cost power will continue for all customers.

3. The stepped rate should be "margin neutral" at all consumption levels. The stepped rate should provide incentives for changes in consumption that do not

result in costs or risks being shifted to other customers. In other words, the stepped rate should also be "margin neutral" for BC Hydro, where margin is revenue less cost, adjusted for risk. This is ensured by "incremental" cost pricing. Under incremental pricing, bill credits granted to customers for their energy savings do not exceed BC Hydro's risk-adjusted value of the saved energy, and bills sent for additional growth cover BC Hydro's incremental costs and risks of acquiring new supply. This is also a change from the historical practice of "rolled in" pricing to "incremental" pricing for consumption changes above or below historic consumption levels.

Rates that are margin neutral must also make use of access rules to prevent margin loss due to rate arbitrage. The rate arbitrage problem is introduced by allowing customers to freely switch among different stepped rate contracts and alternative avenues for access to the wholesale market. If customers are allowed to continually switch back and forth between different rate designs, rate schedules or suppliers, depending on which one provides immediate gain, the resulting rate arbitrage has the potential to shift costs to non-participants.

All stepped rate designs that adhere to the above guiding principles promote changes in consumption or investments that are cost-effective from the perspective of all BC Hydro's customers. The designs aim to ensure that no individual customers are made worse off by the action of another existing customer. And finally, as is shown below, as long as different rate designs rely on incremental pricing to bring about incremental changes in consumption and do not shift historical costs among customers, then different rate designs for different customers could be implemented simultaneously.

The authors of this report do not believe that BC Hydro's guidelines are overly restrictive. The goal is to encourage economic conservation and resource additions, not to encourage arbitrage which can shift costs to other customers. Using these guidelines to screen design alternatives still leaves many stepped rate design choices from which to choose. For example, this report describes rates in which the first-tier rate applies to 60 to 100 percent of a customer's historical consumption, such that Tier 1 rates range from below 1 and 2.6 cents per kWh and Tier 2 rates range from 6 to more than 8 cents per kWh.

1.2.3 Relationship of Stepped Rates and Heritage Contract

Finally, BC Hydro states in the introduction to this filing that it does not believe that the consideration of feasible stepped rate designs should be restricted or tied to the costs or terms and conditions of the Heritage Contract. The analysis described in this report assumes that the revenue requirement for the industrial class of service is the revenues and resulting rates currently collected by BC Hydro's existing 1821 schedule. The industrial class revenue requirement, and the impact of the heritage contract, will ultimately be determined by the BCUC in late 2004. As a result, the report has not attempted to forecast the results of that determination. It proceeds on the premise that stepped rate design proposals should produce the existing 1821 class revenue requirement and should not restrict how future revenue requirements are assigned to the class.

1.3 Key Findings about Stepped Rate Design Choices

Adopting BC Hydro's proposed stepped rate design guidelines leaves a number of feasible stepped rate designs that would meet the objectives of the Energy Plan. The report outlines these choices and presents detailed analysis of the potential consequences of choosing a particular design. The report also attempts to anticipate which rate design choices might be favored by different types of customers. However, the report does not make any recommendations about which rate design is preferable to BC Hydro, nor which design should be adopted by the BCUC. Rather, the purpose of the report is to present a detailed survey of the feasible rate design options for the purpose of educating BC Hydro, customers, the BCUC and the public about the available choices.

Indeed, one key finding of the report is that many of the rate design choices are not mutually exclusive. Different customers may favor different rate designs. Some customers will favor designs that provide long-term rate stability, even if that entails a somewhat higher rate. Other customers may prefer a variable, market-indexed rate, because such a rate provides the lowest expected price over time, and they have the flexibility to shift production schedules in response to changing rates. Some customers may be interested in retail direct access, while others are considering investing in on-site generation. All of these preferences can be accommodated under stepped rate designs. The challenge is to ensure that each of the designs fully compensates BC Hydro, and non-participating customers, for the associated costs and risks they impose, i.e., that each of the designs is margin neutral.

If the stepped rate designs can be made fully margin neutral, there is almost no end to the variations that could be implemented at the request of a customer. Consequently, it may be more useful at this time to develop a *process* by which a customer can request a particular rate form, and a methodology for establishing a rate that is margin-neutral, than to devote resources to developing a preferred rate design that would apply to all customers. The report provides a significant amount of detail about developing margin-neutral rates under a variety of scenarios.

A final key finding of the report is that there are risks to moving to a new, stepped rate design. These risks are described in detail in Section 7 of this report. The stepped rate design could potentially expose BC Hydro to additional market risk if customers respond to the higher Tier 2 rates with significant load reduction and the Tier 2 rate does not accurately reflect BC Hydro's opportunity costs. Moreover, the introduction of retail direct access combined with unconstrained customer rate design choices open up the possibility that customers could profitably arbitrage among different rate designs.

The discussion of risk should not be taken to mean that the stepped rate design is unworkable or undesirable. BC Hydro already faces market risk under its current rate design, and the analysis finds no definitive answer for whether the stepped rate design will, as a whole, increase or decrease BC Hydro's risk exposure. However, the report does recommend a number of policies and limitations on rate design choices that could be employed to reduce BC Hydro's risk and provide protection for non-participating customers.

1.4 Road Map to the Stepped Rate Design Report

The report provides a wealth of conceptual detail regarding various stepped rate design parameters. To assist the reader in digesting this detail and placing it into perspective, we provide this road map to the report.

Section 2 of the report provides the conceptual background for understanding the stepped rate design choices. Section 2 describes the objectives and constraints of a stepped rate design stemming from the Energy Plan, and provides a list of potential rate designs that, in BC Hydro's view, do not meet the objectives and constraints.

Section 3 kicks off the analysis of specific rate design parameters with a discussion of the effects of choosing different cutoff points between the Tier 1 and Tier 2 rates. The cutoff point must be chosen within a narrow band in conjunction with the Tier 1 and Tier 2 rates in order to ensure revenue-neutrality at each customer's baseline historical consumption level. Choosing a Tier 1 cutoff point that is very low could result in a Tier 1 rate that is unreasonably low, while too high a Tier 1 cutoff point would provide little incentive for load reductions. The section then describes a "shopping credit" approach, under which customers receive a constant per-MWh bill credit from BC Hydro for load reduction, regardless of the Tier 1 cutoff. The shopping credit provides additional flexibility around the choice of a Tier 1 cutoff point. The section concludes with some conjecture about which choices might be preferred by different types of customers.

Section 4 of the report focuses on the design of the Tier 2 rate and shopping credit. The Energy Plan calls for the Tier 2 rate to be based on "the cost of new supply". However, there is no single method that perfectly reflects BC Hydro's incremental cost of new supply. The simplicity and stability of a long-term estimate based on the least-cost incremental resource may appear attractive; however, this approach is costly because it requires BC Hydro to bear market risks associated with locking in a rate over a long term. Shorter-term methods, such as market indexes or competitive price quotes, might provide a more time-sensitive indicator of the cost of incremental supply, reducing BC Hydro's risk relative to a longer-term approach. Because customers may have different preferences regarding the tradeoff between rates that are *low* and rates that are *stable*, Section 4 suggests that individual customer preference could play a role in the choice of a Tier 2 design.

Section 5 discusses how the collection of embedded transmission costs from customers who choose retail access for some or all of their energy supply could be handled in the stepped rate design. Two options are presented. The first would continue today's system by charging customers the 1821 demand charge for metered demand served by BC Hydro. The second option would effectively freeze the customer's transmission charge at a historic level by pricing demand changes at the incremental costs to the BC Hydro transmission system. The first option has the advantage of preserving the sharing of costs that are in place today and ensuring that all customers make the same per-MW contribution to the embedded costs of the BC Hydro transmission system. The second option sends a price signal for marginal consumption decisions that is closer to the actual incremental cost to BC Hydro, which in most cases is very near zero[1].

Section 6 provides an overview of the risk factors that are associated with the introduction of the stepped rate design. Risk factors include new market risks from customers pursuing load reduction opportunities, arbitrage risks that stem from customer rate design choices, and other risks that are specific to various forms of stepped rate design. The section recommends a number of strategies for mitigating these risks. These include regular updates of the Tier 2 rates, fixed terms of at least twelve months for any customer rate design choices, and Tier 2 rates and shopping credits that are adjusted for market risk. Finally, supplemental mechanisms are recommended including a phased implementation with global limits on participation in any credit program until the rate design is thoroughly tested.

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[1] During times of peak load, the marginal cost is not zero, particularly for some locations such as Vancouver Island and the Lower Mainland.

2 Stepped Rate Design

2.1 *Introduction*

Policy Action #21 requires BC Hydro to implement "new stepped and time-of-use" pricing. A stepped rate design features different rates for different blocks of energy consumption. For example, consumption up to "*X*" MWh is priced at a "Tier 1" rate, consumption above "*X*" MWh is priced at a "Tier 2" rate. The Tier 1 and Tier 2 rates and the cutoff point between the tiers are design parameters that can be set to meet various policy objectives. In some jurisdictions, upper tier rates have been set lower than the first tier, resulting in a declining block rate structure that offers a volume discount. For BC Hydro, the Energy Plan envisions that the Tier 2 rate will "reflect the cost of new supply". While in theory the cost of new supply could be either higher or lower than the embedded cost of BC Hydro's existing resources, the low embedded cost of existing hydro resources means that the Tier 2 rate will be, as contemplated in the Energy Plan, higher than the Tier 1 rate for the foreseeable future.

2.2 *Stepped rate design objectives and constraints*

The stepped rate design is intended to provide customers and resource developers with price signals that give them an incentive to make energy consumption and production decisions that are beneficial to the province. Policy Action #21 envisions that stepped rates "will encourage these customers to meet part of their electricity needs through conservation and energy efficiency, or from other sources (self-generation or IPP purchases), where they can do so cost-effectively." Policy Action #21 also envisions "time-of-use rates [that] will encourage customers who can manage the timing of their electricity use to shift consumption to low-priced off-peak periods."

The Energy Plan outlines a number of other objectives that the stepped rate should meet. The stepped rate should be revenue-neutral to "keep rates low overall", should allow customers to "meet all or a portion of their consumption from private generation", and should allow existing customers to "continue to benefit from electricity trade".

The objectives for the stepped rate design can be used to develop a list of rate design requirements. These include the following:

1. **The Tier 1 rate must be set at a rate that captures BC Hydro's low-cost resource base**. This ensures that BC Hydro's large industrial customers continue to share in the benefits of these resources.
2. **The Tier 2 rate must reflect the cost of new supply**. This will provide a price signal to customers to invest in conservation or self-generation that reduces the overall cost to serve load on the BC Hydro system.
3. **The rate design must not shift costs among customers or impose new, uncompensated risks on other customers**. This ensures that BC Hydro's earnings are neither enhanced nor reduced and that the new rate will have no impact on the level of benefit each customer receives from trade and from BC Hydro's existing resources.
4. **The rate design must be neutral with respect to customer's choice of energy supplier (BCH, IPP or marketer), self-generation, or DSM**.

This will ensure that customers can make unbiased decisions among the variety of ways to meet their energy needs.

5. **The rate design must be easy to understand and implemented with minimal regulatory process**. This will avoid unnecessary implementation expense and will ensure that customer choices are clear and well-understood.

2.3 Rate designs that are "out-of-bounds"

These requirements rule out a number of potential design choices. Rate designs that include the following features do not meet the design requirements and are therefore not considered in this report:

1. **Customers receive title to heritage energy**. Giving customers title to heritage energy would require BC Hydro to recover from other customers all new costs associated with providing electric service in British Columbia. This would violate the requirement that the stepped rate not shift costs among customers or customer classes.
2. **Tier 1 rate set at the market value of energy**. This would be tantamount to mandatory retail restructuring. Because the market price of energy is likely to be higher than BC Hydro's existing rates, exposing industrial customers to market prices for their entire load does not meet the requirement that customers continue to benefit from BC Hydro's low-cost hydro resources.
3. **Tier 2 rate set lower (or higher) than the cost of new supply**. The Tier 2 rate is the rate at which incremental changes in customer consumption

and demand will be priced. Tier 2 rates that are set significantly higher than the cost of new supply would encourage wasteful investments in self-generation and raise the overall cost of meeting the energy needs of BC Hydro's industrial customers. Tier 2 rates that are set lower than the cost of new supply would not provide sufficient financial incentives to capture all cost-effective conservation and self-generation opportunities.

4. **Growing demand met at 1821 tariff**. The Energy Plan calls for stepped rates where "the last block of energy consumed should reflect the cost of new supply". This means that consumption priced at Tier 1 rates must be fixed, and that growing customers must either meet their incremental energy needs at the Tier 2 rate or acquire alternative supplies.
5. **Punitive entry and exit requirements that prevent meaningful customer choice**. Policy Action #21 envisions that large customers will have the ability to serve "all or a portion of their consumption from private generation." In order to meet this goal, customers must be meaningfully able to choose retail direct access, free of the onerous requirements that have accompanied such a choice in other jurisdictions.
6. **Increased costs to other customers as a result of customer choices**. While a successful stepped rate design will afford customers a meaningful choice of suppliers, it will also protect non-participating customers from the consequences of these choices. Customers who choose self-generation, energy efficiency or direct access must be prepared to bear the

full costs and risks associated with that choice, and must not be allowed to shift those costs and risks to other customers.

7. **Complete redesign of 1821 rate structure**. A fundamental change to the 1821 tariff would require a reallocation of BC Hydro's embedded costs among customer classes, triggering a lengthy regulatory proceeding. To the extent possible, the stepped rate design must work within the regulatory framework of the existing industrial class tariff designs.
8. **Substantial changes to BC Hydro's Wholesale Transmission Service (WTS) design**. The new BC Hydro Transmission Company is expected to initiate a rate proceeding by the end of 2004. In the meantime, to avoid unnecessary regulatory process, any changes to the industrial tariffs must not require substantial changes to the WTS design.

2.4 Stepped rate design parameters

While the requirements described above define a set of acceptable design options, there are a number of important design choices that must be made. The most important choices are the Tier 1 and Tier 2 rates and the cutoff point between the tiers. Other key parameters include how to credit customers for reduced energy purchases from BC Hydro and how to charge customers for transmission.

The rate design parameters must be chosen carefully and in concert with each other so as to balance the policy objectives described above. For example, if the Tier 1 cutoff is chosen to reflect a specific quantity of energy and the Tier 2 rate is fixed to reflect the cost of new supply, there is only one Tier 1 rate that is revenue-neutral for BC Hydro, i.e., that does not change the total energy bill of a customer whose energy consumption does not change. Alternatively, if the Tier 1 and Tier 2 rates are fixed, there is only one Tier 1 cutoff point that is revenue neutral.

2.5 "Margin-neutral" stepped rate design

In order to avoid shifting costs among customers, the new rate design must be "margin-neutral". A rate design is margin-neutral if BC Hydro's net margin from all of its activities, including sales of energy to retail customers and wholesale market trading, does not change incrementally from implementation of the rate design.

Margin-neutrality has two aspects. First, margin-neutrality means that the total bill that a customer receives under the new stepped rate must be the same as the bill it receives today under Schedule 1821, provided that the customer's energy consumption has not changed from its historical pattern. That is, the rate design must be "bill-neutral" (from BC Hydro's perspective, "revenue-neutral") at historical consumption levels. Second, margin-neutrality means that customer choices under the stepped rate design must not adversely affect BC Hydro's earnings or shift costs or uncompensated risks onto non-participating customers. Changes to BC Hydro's revenues as a result of customer choices must be exactly offset by cost changes.

BC Hydro's revenue structure will change as a result of customer choices under the stepped rate design. If an industrial customer invests in self-generation, the gross revenues that BC Hydro collects from its industrial customers will be lower. However, this investment also creates surplus energy that BC Hydro can sell, or alternatively reduces the energy that BC Hydro must procure on the wholesale market. As long as the sum of BC Hydro's revenues from all sources less the sum of BC Hydro's costs from all sources does not change, the stepped rate design is considered to be margin neutral.

3 Stepped Rate Design Parameter 1: Choice of Tier 1 cutoff

The most important rate design parameter is the choice of the Tier 1 cutoff point, because it drives the choices of the other rate design parameters. Therefore, it is useful to consider the advantages of a variety of approaches.

3.1 Simple tiered rate design

Choosing a Tier 1 cutoff point requires establishing a "customer baseline" (CBL) based on some estimate of historical consumption. This baseline could be calculated in a number of ways. For example, the calculation could be based on the customer's consumption in the most recent year before implementation of the rate design, i.e., 2003. However, 2003 may not be a typical year for many industrial customers due to the global economic slowdown. An alternative method would be to base the CBL on average consumption from 2000-2002. This alternative also has a disadvantage; this period includes the period from mid-2000 through mid-2001 when western electricity markets were in turmoil, and when customers may have voluntarily reduced their loads in response to BC Hydro load management programs. A simple formula may not capture these effects and may unfairly penalize customers for responding to BC Hydro programs. The method of choosing a CBL, including the determination of a CBL for new customers and adjusting the CBL for existing customers who change their production, is a topic that may be more easily addressed in workshops and consultations rather than through a formal evidentiary hearing.

Perhaps one of the most challenging CBL issues is the determination of baseline usage for new customers. If BC Hydro is going to allow new customers to take service on the stepped rate, the question arises of whether it should also provide comparable adjustments in the baseline level of usage for existing customers who make new investments in their businesses. The objectives of providing proper price signals and comparable service need to be carefully balanced.

Once a customer baseline is established, the Tier 1 cutoff is set at *Y*% of the CBL. Consumption up to *Y*% is priced at the Tier 1 rate, while consumption above *Y*% is priced at the Tier 2 rate. The parameter *Y* can range from a small number, e.g., 60%, all the way up to 100% of the CBL. The smaller *Y* is, the lower the Tier 1 rate will be and the larger the jump will be to the Tier 2 rate. At *Y*=100%, the Tier 1 rate is the same as the 1821 energy rate since the design must be revenue-neutral.

An example of a stepped rate with different Tier 1 cutoff points is presented in the table below. The table shows the impact of choosing the Tier 1 cutoff at 60%, 80% and 100% of CBL for a customer with monthly electricity consumption of 10,000 MWh. In each case, the historical customer bill is based on the 1821 energy rate of 2.599¢/kWh[2] (demand charges are ignored for this simple illustration) and the Tier 2 rate is assumed, for illustrative purposes, to be 6.2¢/kWh.[3] Given these assumptions, the Tier 1 rate is calculated so as to achieve revenue-neutrality at historical consumption.

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[2] The 2.599 ¢/kWh is used throughout this report under the assumption that it reflects the overall costs of serving the industrial sector at historical consumption levels. The 2.599 ¢/kWh may be subject to future change if it does not adequately reflect the costs of supply.

[3] Detailed assumptions for the 6.2 cent/kWh rate are included in Table 7.

Table 1. Monthly Bill under Three Tier 1 Cutoff Choices

	Tier 1 Cutoff: 60%	Tier 1 Cutoff: 80%	Tier 1 Cutoff: 100%
1821 class average rate (¢/kWh)	2.599	2.599	2.599
Monthly consumption (MWh)	10,000	10,000	10,000
Tier 1 (lower tier), MWh up to:	**6,000**	**8,000**	**10,000**
Tier 1 monthly consumption (MWh)	6,000	8,000	10,000
Tier 1 rate (¢/kWh)	0.198	1.699	2.599
Tier 1 monthly bill	$11,900	$135,900	$259,900
Tier 2 (upper tier), MWh greater than:	**6,000**	**8,000**	**10,000**
Tier 2 monthly consumption (MWh)	4,000	2,000	-
Tier 2 rate (¢/kWh)	6.200	6.200	6.200
Tier 2 monthly bill	$248,000	$124,000	$0
Total under new rate design			
Tier 1 + Tier 2 monthly bill	$259,900	$259,900	$259,900
Average rate for all consumption	2.599	2.599	2.599

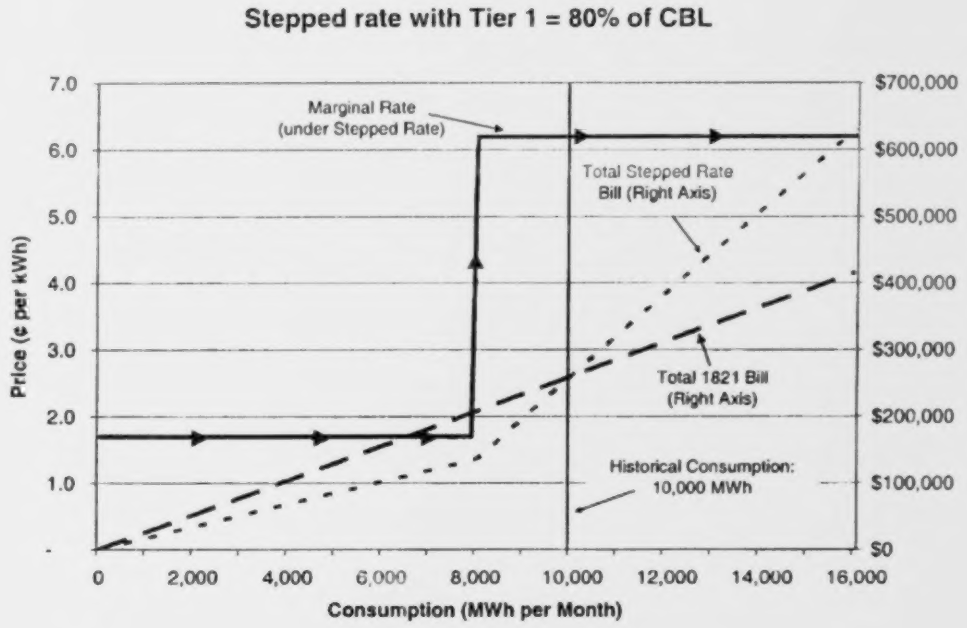
As the first column of the table demonstrates, choosing a Tier 1 cutoff at 60% of CBL can lead to a Tier 1 rate that is unreasonably low. Under these assumptions, the Tier 1 rate for a cutoff point of 60% of CBL is only 0.2¢/kWh. At the other end of the spectrum, a Tier 1 cutoff set at 100% of CBL results in a Tier 1 rate that is identical to the 1821 rate. This would result in a price signal based on the cost of new supply for incremental load growth, and a signal based on embedded costs for load reduction (e.g., conservation or self-generation).

A Tier 1 cutoff higher than 100% of CBL would result in pricing for incremental load that reflects average costs rather than the incremental cost of new supply. As mentioned above, this contradicts the direction of the Energy Plan that the trailing block of the stepped rate reflects the cost of new supply. This option is therefore not discussed in detail in this report.

These options are presented graphically in the charts below. The figures show both the marginal, per-kWh price (on the left axis) and the total bill (on the right axis) at different consumption levels.

Figure 1 below illustrates the effect of setting the Tier 1 cutoff at 80% of CBL. The resulting Tier 1 rate is 1.7¢/kWh, which is approximately 35% below the current 1821 rate and 70% below the illustrative Tier 2 rate of 6.2¢/kWh. The customer's bill under a stepped rate rises sharply beginning at 8,000 MWh per month; the customer pays $136,000 for the first 8,000 MWh, and $124,000 for the next 2,000 MWh. The customer is rewarded at the Tier 2 rate for reducing energy consumption by up to 20 percent below its historical level. The customer's total bill under schedule 1821 is a straight line, reflecting the constant energy rate of 2.599¢/kWh. The total bills under 1821 and the stepped rate are the same at the historical consumption level of 10,000 MWh, reflecting bill neutrality.

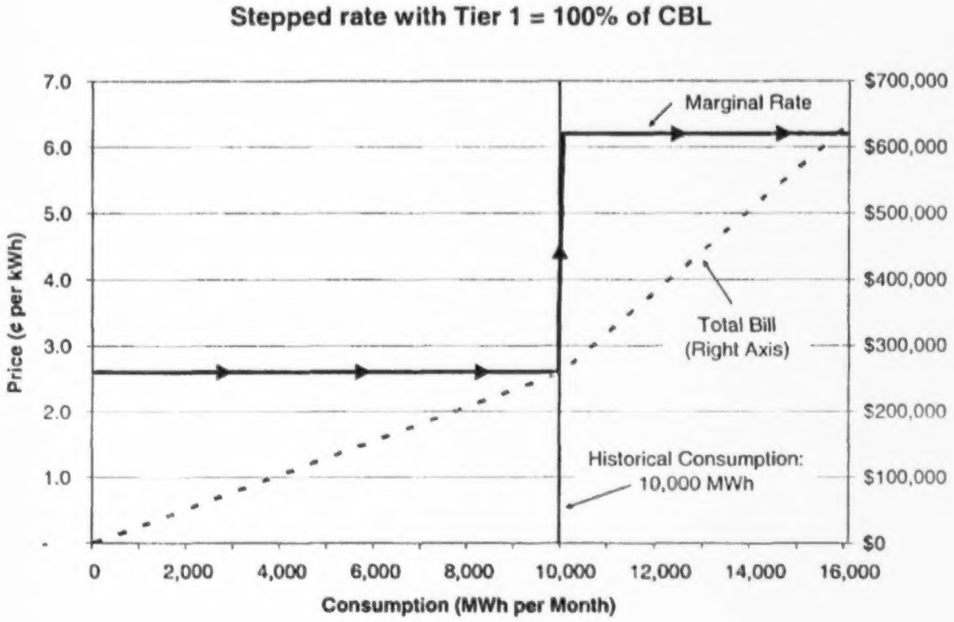
Figure 1



Stepped rate with Tier 1 = 80% of CBL

Figure 2 illustrates the effect of setting the Tier 1 cutoff at 100% of CBL: the Tier 1 rate does not change from the 1821 rate of 2.599¢/kWh. This reduces the complexity of calculating a Tier 1 rate, but rewards the customer for reducing consumption at a rate that, in this example, is well below the cost of new supply. This does not provide a comparable signal for customers to invest in energy conservation or grow their businesses.

Figure 2



These examples demonstrate that the Tier 1 cutoff point must be chosen in a fairly narrow range in order to meet the objectives of the Energy Plan. A low cutoff point can result in Tier 1 energy rates that are unreasonably low, while a high cutoff point may not provide a sufficient incentive for customers to invest in energy efficiency measures or in self-generation.

3.2 Tier 2 "shopping credit" for reduced load served by BC Hydro

The limitations associated with choosing a Tier 1 cutoff point that is too high can be solved by pairing the stepped rate with a mechanism that credits the customer for reduced energy consumption based on the cost of new supply. This bill offset is commonly referred to as a "shopping credit". Such a mechanism would give the customer the same incentive to conserve regardless of the choice of a Tier 1 cutoff. The shopping credit could be based on short-term prices that reflect BC Hydro's opportunity costs, similar to a real-time-pricing (RTP) or time-of-use (TOU) rate, or a longer-term estimate based on its displacement of new resources.[4] A shopping credit mechanism is consistent with Energy Plan's call for "time-of-use rates [that] encourage customers who can manage the timing of their electricity use to shift consumption to low-priced off-peak periods". A shopping credit has been implemented in a number of jurisdictions in order to allow retail direct access without undertaking a full unbundling of retail rates, which in this case is precluded by the rate design objectives and constraints.

3.2.1 Shopping credit: Conceptual overview and historical precedents

Figure 3 below illustrates the broad types of costs that are generally included in BC Hydro's 1821 rates. These costs include, among other things, transmission, generation capacity and energy, and social programs like Power Smart. The shopping credit would allow BC Hydro's industrial customers to receive credits for self-supply that reflects market value. In all stepped rate designs, customers can self-supply energy. In some forms, they can also self-supply ancillary services and transmission.

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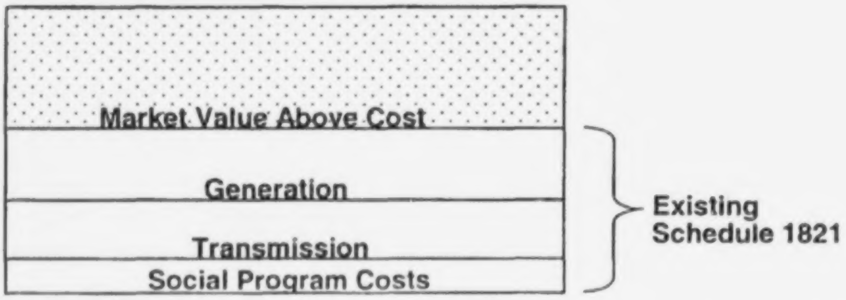
[4] Three reasons that the shopping credit produces more risk than BC Hydro's existing RTP rate (Schedule 1848): (1) the RTP rate is updated on a daily basis, (2) the RTP rate only pays market based credits for consumption greater than 25% of the customer's CBL, and (3) the potential for load reduction is greater under the current weak economic environment. Strategies to mitigate these risks are discussed in Section 6.

Figure 3



Customers who choose to self-supply their electricity needs by investing in generation, contracting with a third-party supplier or conserving power through demand-side management, receive credits on their bills for services that they no longer need to purchase from the utility. However, since the utility's bundled retail rates remain in place, customers who choose to self-supply need not cut their ties to the utility to do so, providing them with a "safety net" of reliable, default supply service. The shopping credit has been extensively used in restructured markets where there is a defined transition period from bundled to unbundled rate structures. During the transition period, the utility continues to be the supplier of last resort, but offers shopping credits to any of its customers who choose to self-supply a portion of the energy needs. The shopping credit rates set by the utility for energy, transmission and ancillary services become the "prices to beat" for customers deciding whether to stay with the default utility or self-supply.

During the four year period between 1997-2001, Sacramento Municipal Utility District (SMUD) in California offered a direct access (DA) option to its retail customers that had many similarities to the proposed Stepped Rate application in B.C. Participants continued to be metered for consumption and billed by SMUD according to the applicable tariff. SMUD also metered the energy supplied by a third-party or self-generated portion of the customer's supply and credited the DA customer's bill at SMUD's market-based procurement cost and any avoided high-voltage transmission charges. Since this option did not require either functional unbundling of rates or a restructuring of markets, this form of shopping credit used by SMUD is the most relevant and applicable to BC Hydro's stepped rate implementation.

Other well-known applications of the shopping credit approach include Ontario, Canada, California and in Pennsylvania, New Jersey and Maryland (PJM) Interconnection. For example, in Ontario, all industrial customers had access to the hourly spot energy market and some limited ancillary services markets, which were run by the IMO (Independent Market Operator). Customers taking service from the spot energy market were credited for the pool price times the energy used. For customers who elected to self-provide a portion of their energy needs, transmission was charged based on their metered utility demand, net of any load served by generators behind the customer's meter.

A third model is the California utilities' tariff structure in effect while the California Power Exchange (PX) was still in existence. Instead of posting a price to beat, the California utilities indexed the amount of shopping credit to the actually hourly PX market prices during each month. Customers could negotiate with third-party suppliers to lock in savings vis-à-vis the PX index price.

Finally, the shopping credit implemented in PJM was markedly different from the California version. The credit that the utilities offered in that market was based on a forecast of energy prices. This provided a clear and stable "price to beat" for third-party suppliers. This stable form of shopping credit facilitated more self-supply in PJM than in California.

3.2.2 Shopping credit in the context of BC Hydro's stepped rates

Figure 4 illustrates the shopping credit concept. Consumption up to the Tier 1 cutoff, which is assumed here to be 100% of CBL but could be set at any level, is billed at the Tier 1 rate, and consumption above 100% of CBL is billed at the Tier 2 rate.[5] . However, the customer would also receive a shopping credit from BC Hydro at the "Shopping Credit Rate", assumed here to be equal to the Tier 2 rate, for reducing consumption below the Tier 1 cutoff. The net effect is a bill that declines rapidly as consumption falls from the Tier 1 cutoff. In this example, the customer's net electricity bill from BC Hydro is zero at a consumption level of 6,000 MWh.

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[5] While the shopping credit concept is most easily understood with rates that have a Tier 1 quantity of 100% of CBL, the shopping credit can also be implemented with designs that have less than 100% of a customer's CBL billed at Tier 1 rates. For example, if a 90% CBL design were used, it would be equivalent to providing a shopping credit for up to 10% of a customer's CBL.

Figure 4

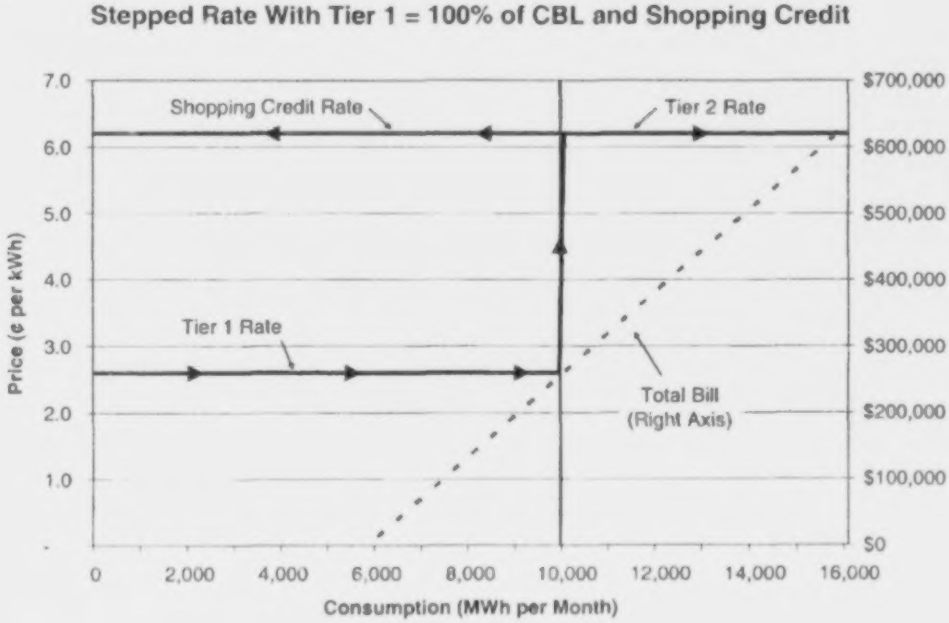


Table 2 below presents a numerical example. The example shows a shopping credit for a customer that reduces its purchases of energy from BC Hydro to zero, assuming a Tier 1 cutoff at 100% of CBL. The first column shows the customer's monthly bill if it takes its full 10,000 MWh load from BC Hydro. The customer consumes exactly at its CBL, so its entire consumption is priced at the Tier 1 rate of 2.599¢/kWh. Ignoring the 1821 demand charge, the customer's monthly bill is $259,900, which meets the revenue neutrality goal because it is the same as the historical monthly bill for 10,000 MWh.

Table 2. Monthly Bill with Shopping Credit

	BC Hydro	Alternative Supplier
Monthly customer baseline amount (MWh)	10,000	10,000
Monthly consumption taken from BC Hydro (MWh)	10,000	-
Monthly consumption taken from Alternative Supplier (MWh)	-	10,000
Total monthly consumption (MWh)	*10,000*	*10,000*
BC Hydro Bill		
Tier 1 (lower tier), MWh up to:	**10,000**	**10,000**
Tier 1 monthly consumption (MWh)	10,000	10,000
Tier 1 rate (¢/kWh)	2.599	2.599
Tier 1 monthly bill	$259,900	$259,900
Tier 2 (upper tier), MWh greater than:	**10,000**	**10,000**
Tier 2 monthly consumption (MWh)	-	-
Tier 2 rate (¢/kWh)	6.200	6.200
Tier 2 monthly bill	$0	$0
Total monthly bill from BC Hydro	*$259,900*	*$259,900*
Alternative Supplier Bill		
Alternative Supplier monthly consumption (MWh)	-	10,000
Alternative Supplier rate (¢/kWh)	6.100	6.100
Total monthly bill from Alternative Supplier	*$0*	*$610,000*
Shopping Credit		
Shopping credit quantity	-	10,000
Shopping credit rate	(6.200)	(6.200)
Total shopping credit	*$0*	*($620,000)*
Total Monthly Bill		
Monthly bill before shopping credit	$259,900	$869,900
Shopping credit	$0	($620,000)
Monthly bill after shopping credit	$259,900	$249,900
Average rate for all consumption	2.599	2.499

The second column illustrates how the shopping credit allows the customer to pursue alternative supplies of energy for its entire load. The customer continues to pay the bundled, 1821 rate to BC Hydro for its CBL of 10,000 MWh, or $259,900. The customer also pays the alternative supplier $610,000 for taking 10,000 MWh of energy at the supplier rate of 6.1¢/kWh. This leaves the customer with a gross bill of $869,900. The customer then receives a shopping credit from BC Hydro equal to BC Hydro's Tier 2 rate, assumed to be 6.2¢/kWh. With the shopping credit, the customer's net monthly bill is $249,900. This is $10,000 less than the bill under BC Hydro service, reflecting the modest savings the customer achieves by selecting an alternative supplier that offered a rate that is slightly more attractive than BC Hydro's Tier 2 rate.

The right-hand column in the table is labeled "alternative supplier," but a customer could also use the shopping credit to fund energy efficiency or self-generation investments. The shopping credit approach allows a customer to seek alternatives for its entire load at a savings equal to the cost of new supply, rather than the 1821 rate. This enables the customer to finance much larger investments than a tiered rate structure in which only a relatively small portion of load is priced at the Tier 2 rate. This may not matter much for energy efficiency measures, which do not generally reduce a customer's consumption by more than a few percentage points; however, investments in self-generation may not be economic without a shopping credit unless a substantial portion of the customer's load reduction is credited at the Tier 2 rate.

3.2.3 Shopping credit with shopping credit rate lower than Tier 2 rate

The examples described thus far have assumed that the shopping credit for reducing purchases from BC Hydro is equal to the Tier 2 rate at which increased purchases are priced. However, this is not the only design for a shopping credit, and there are a variety of reasons why BC Hydro might wish to establish a shopping credit rate that differs from the Tier 2 rate for incremental:

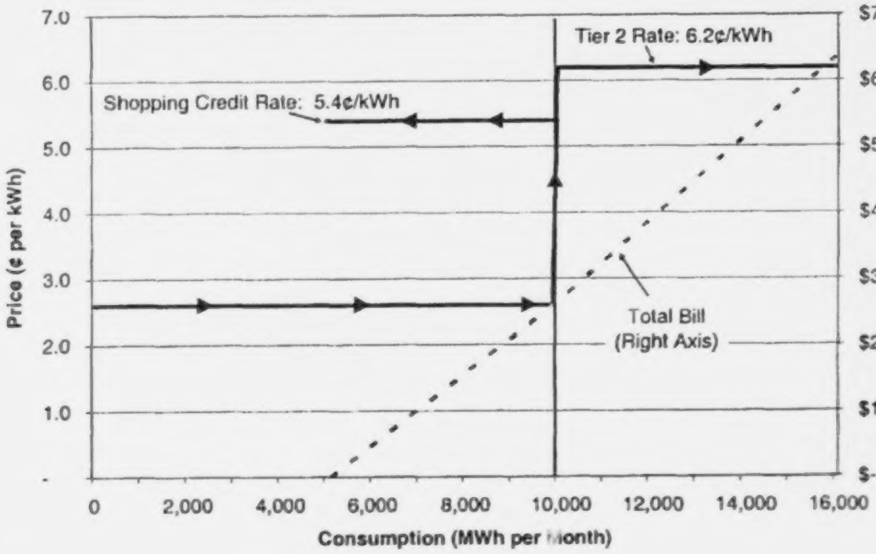
- **Market price volatility**. Depending on how the shopping credit is calculated, crediting customers for load reductions may expose BC Hydro to market risks. For example, if BC Hydro fixes the shopping credit rate for a period of one or more years, the market price at which BC Hydro may be able to resell the power made available through customer load reduction could either be higher or lower than the shopping credit rate. The longer the price is locked in, the higher BC Hydro's risk exposure. An appropriate spread between the shopping credit and Tier 2 rates would compensate BC Hydro for the price risk inherent in a rate that is fixed over time.

◆ **Margin for non-participating customers**. The margin-neutrality goal requires that both participating and non-participating customers be held harmless at historical consumption levels. However, the goal says nothing about how to allocate the gains that accrue when a customer makes use of the shopping credit to reduce consumption below its CBL. Because all customers are paying a share of BC Hydro's revenue requirement through retail rates, it may be desirable to allocate them a share of these gains through a shopping credit that is slightly below the Tier 2 rate. However the size of the asymmetry should be relatively small in order to avoid diluting the price signal that would spur efficient investment by participating customers.

◆ **Ancillary services**. The Tier 2 rate may include ancillary services such as regulation, load following and reserves required for reliable transmission operations. However, customer load reductions may not proportionately reduce BC Hydro's overall ancillary service requirements, particularly if the load reductions are transitory. Therefore, it may not be appropriate to include the full value of ancillary services in load reduction credits.

- **Capacity requirements**. If BC Hydro cannot count on the load reductions occurring, it may have to provide backup capacity in case the customer's consumption is higher than expected. Therefore, it may not be appropriate to include the full value of capacity in load reduction credits.
- **Load profile**. Loads can be more or less costly to serve, depending on the time profile of these loads. If the shape of load reductions is different from the shape assumed in calculating the Tier 2 rate, incremental and decremental load would have different value to BC Hydro.

Figure 5



Stepped Rate With Shopping Credit Less Than Tier 2 Rate

Figure 5 depicts a rate design featuring a spread between the shopping credit and Tier 2 rates. Growing customers are charged the Tier 2 rate of 6.2¢/kWh for all consumption above their CBL. Customers who reduce their load below the baseline are credited at the shopping credit rate of 5.4¢/kWh, reflecting a spread of 0.8¢/kWh.

3.2.4 Shopping credit with administrative limit on load reduction

Customer load reduction can occur as a result of: 1) energy efficiency, defined as the same or greater production with less energy consumption; 2) self-generation, where the customer installs and operates behind-the-meter generation or cogeneration; and 3) partial or full shutdown, where the customer reduces energy consumption by reducing production. Additionally, customers choosing direct access reduce the energy consumption supplied by BC Hydro, although the physical load does not change. While the energy policy is intended to encourage cost-effective investments in efficiency, self-generation, load management or direct access, a poorly designed shopping credit could result in another, less desirable outcome: permanent facility shutdown. If customers are granted full shopping credits for any load reduction regardless of the cause, there may be situations in which it is more profitable for a customer to shut a facility permanently and take the shopping credit than to continue operations in British Columbia. Pricing load reductions this way has the same characteristics as direct allocations of heritage resources. Customers have the incentive to sell their low-cost power back to BC Hydro any time the market price exceeds the cost-based rate.

One mechanism for addressing this problem might be to establish a limit, e.g., *Z%* of CBL, beyond which customers would be required to make an application in order to receive a full shopping credit. Customers would be allowed to claim a credit with no questions asked for load reduction less than *Z%*. For credits beyond the limit, the customer would apply to BC Hydro or to the BCUC to receive the credit. Real, verifiable investments such as energy efficiency projects or self-generation would qualify for the shopping credit up to the full amount of load reduction, as would customers who reduce load by choosing a third-party supplier through retail direct access.[6] Under this type of screening process, customers who permanently shut their facilities would not qualify for credits.

Figure 6

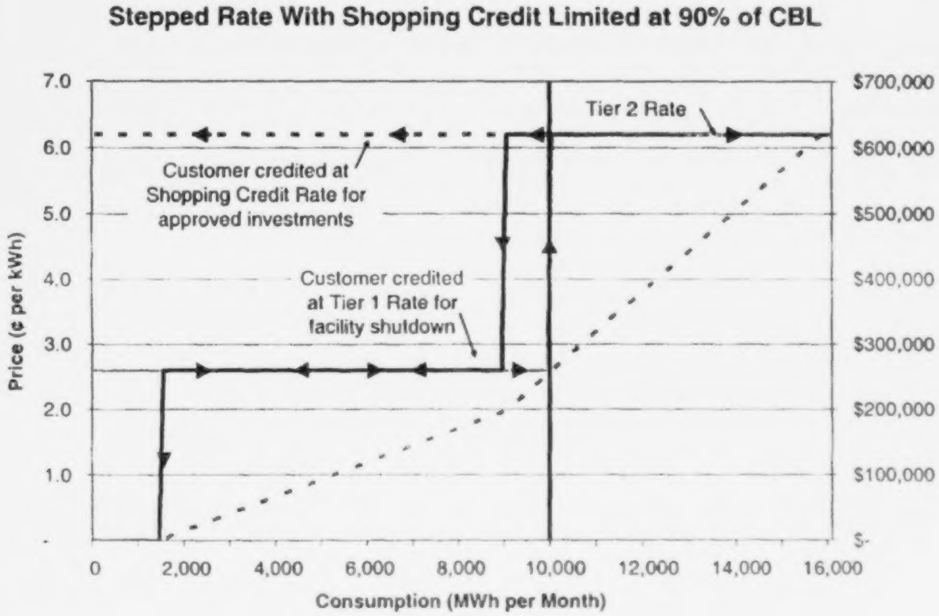


Figure 6 illustrates a limit mechanism set at 10% of CBL. If a customer reduced load from 10,000 to 9,000 MWh, the customer would continue to pay BC Hydro for 10,000 MWh at the Tier 1 rate, but would receive a shopping credit at the Tier 2 rate for load reductions up to 1,000 MWh. Further reductions only result in bill savings at the Tier 1 rate of 2.599¢/kWh.

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[6] Load management programs could also qualify, although the BCUC may wish to establish certain conditions to reflect desired social values. For example, when the Bonneville Power Administration purchased load reductions from aluminum smelters during the 2000-01 western electricity crisis, it placed a number of conditions on the use of funds received by the smelters. Among others, these included requirements that employees continue to be paid and that the proceeds could be used only for investment in power supplies or to improve facility productivity.

3.3 Customer Perspectives on Tier 1 cutoff design

This section analyzes the various Tier 1 cutoff options from the perspective of different types of customers. The analysis includes bill comparisons and discussion of how each type of customer would fare under each option. Three broad categories of customer are considered:

- **Growing customers**. Customers whose electricity consumption is likely to increase after the implementation of the stepped rate design.
- **Customers with modest load reductions**. Customers whose energy purchases from BC Hydro are likely to be somewhat lower after the implementation of the stepped rate design. This category includes customers who wish to invest in energy conservation or who are likely to see a slow decline in production at British Columbia facilities.
- **Customers with substantial load reductions.** Customer whose energy purchases from BC Hydro are likely to be substantially lower after the implementation of the stepped rate design. This category includes customers who wish to invest in self-generation or cogeneration facilities, customers who are interested in purchasing energy from a supplier other than BC Hydro for large portions of their load, or customers who are likely to permanently close their British Columbia facilities.

The rate design forms used for the analysis in this section are shown in Table 3 below. The rate design options include an 80% CBL case (Tier 1 cutoff set at 80% the customer baseline), a 90% CBL case, a 100% CBL case, and an alternative 100% CBL case with a shopping credit set, for the sake of simplicity, at the Tier 2 rate. The bill comparisons use the same, 10,000 MWh/month customer depicted in the examples above. The Tier 2 rate is assumed to be the same, 6.2¢/kWh, in all cases. The Tier 1 rates vary depending on the quantity billed under Tier 1 and Tier 2, and are as shown in the table below. The rate design parameters, including Tier 1 cutoff, Tier 1 rate, and Tier 2 rate are assumed to be fixed at a given point in time and are not updated based on the new customer behavior.

Table 3. Rate Designs Considered in Customer Analysis, 10,000 MWh Customer

Baseline	**80% CBL**	**90% CBL**	**100% CBL**	**Shopping Credit**
1821 class average rate (¢/kWh)	2.599	2.599	2.599	2.599
Historical Monthly consumption (MWh)	10,000	10,000	10,000	10,000
Tier 1 (lower tier), MWh up to:	**8,000**	**9,000**	**10,000**	**10,000**
Tier 1 monthly consumption (MWh)	8,000	9,000	10,000	10,000
Tier 1 rate (¢/kWh)	1.699	2.199	2.599	2.599
Tier 1 monthly bill	$135,900	$197,900	$259,900	$259,900
Tier 2 (upper tier), MWh greater than:	**8,000**	**9,000**	**10,000**	**10,000**
Tier 2 monthly consumption (MWh)	2,000	1,000	-	-
Tier 2 rate (¢/kWh)	6.200	6.200	6.200	6.200
Tier 2 monthly bill	$124,000	$62,000	$0	$0
Tier 2 Shopping Credit, MWh less than:	**8,000**	**9,000**	**10,000**	**10,000**
Shopping credit quantity (MWh)	-	-	-	-
Shopping credit rate (¢/kWh)	-	-	-	6.200
Total monthly shopping credit	-	-	-	$0
Tier 1 + Tier 2 monthly bill	*$259,900*	*$259,900*	*$259,900*	*$259,900*
Average rate for all consumption	*2.599*	*2.599*	*2.599*	*2.599*

3.3.1 Customers with growth in energy purchases from BC Hydro

Under the current framework, BC Hydro procures new energy supplies on behalf of growing customers and blends the costs of the new supplies with the cost of existing resources. Because new resources tend to be costlier than existing resources, customer growth generally leads to upward pressure on rates over time. However, the cost of the new resources is spread over a large customer base, so the bill impact for any individual customer is typically modest.[7]

The new stepped rate will change this framework. In order to be consistent with the Energy Plan, the cost of new supply will be assigned to growing customers, rather than rolled in and spread to all customers. Growing customers will thus face higher bills than they would under the existing 1821 tariff, and will pay the cost of new supply for all incremental consumption.

The table below shows the monthly bills for a customer whose consumption grows by 20% over historical levels. It is immediately apparent that a growing customer is indifferent to the choice of a Tier 1 cutoff. In each case, the customer requires an additional 2,000 MWh of electricity, which is billed at the Tier 2 rate. In each case, the customer's bill grows by 2,000 * 6.2¢ = $124,000, and the customer's average rate for its entire consumption grows from 2.599¢/kWh to 3.199¢/kWh. Because the Tier 1 rate and cutoff were designed to be revenue-neutral at historical consumption levels, the customer's bill is the same under each design.

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[7] Alternatively, under a mandatory stepped rate, growing customers may prefer growing CBLs that match their load growth. Both of these rate designs are inconsistent with the Energy Plan and are therefore not discussed in this report.

Table 4. Tier 1 Cutoff Analysis, Growing Customer

Growing Customer	80% CBL	90% CBL	100% CBL	Shopping Credit
1821 class average rate (¢/kWh)	2.599	2.599	2.599	2.599
Historical monthly consumption (MWh)	10,000	10,000	10,000	10,000
New monthly consumption (MWh)	12,000	12,000	12,000	12,000
Tier 1 (lower tier), MWh up to:	**8,000**	**9,000**	**10,000**	**10,000**
Tier 1 monthly consumption (MWh)	8,000	9,000	10,000	10,000
Tier 1 rate (¢/kWh)	1.699	2.199	2.599	2.599
Tier 1 monthly bill	$135,900	$197,900	$259,900	$259,900
Tier 2 (upper tier), MWh greater than:	**8,000**	**9,000**	**10,000**	**10,000**
Tier 2 monthly consumption (MWh)	4,000	3,000	2,000	2,000
Tier 2 rate (¢/kWh)	6.200	6.200	6.200	6.200
Tier 2 monthly bill	$248,000	$186,000	$124,000	$124,000
Tier 2 Shopping Credit, MWh less than:	**8,000**	**9,000**	**10,000**	**10,000**
Shopping credit quantity (MWh)	-	-	-	-
Shopping credit rate (¢/kWh)	-	-	-	6.200
Total monthly shopping credit	-	-	-	$0
Tier 1 + Tier 2 monthly bill	*$383,900*	*$383,900*	*$383,900*	*$383,900*
Average rate for all consumption	*3.199*	*3.199*	*3.199*	*3.199*

3.3.2 Customers with modest reductions in energy purchases from BC Hydro

Customers whose loads will decline in the future have a different perspective. Table 5 shows the impact of the different designs on a customer that reduces its BC Hydro purchases by 20%. The 80% CBL design is favorable to these customers due to its low Tier 1 rate of 1.699¢/kWh; under this design, a customer who reduces BC Hydro purchases by 20% would avoid all Tier 2 charges and pay the Tier 1 rate for its entire monthly consumption. The Tier 1 rate under the 90% CBL design is somewhat higher at 2.199¢/kWh, which leads to a higher BC Hydro bill for this customer than the 80% CBL design. The 100% CBL design results in an average rate equal to today's 1821 rate – reduced purchases are priced at today's embedded cost rate.

Table 5. Tier 1 Cutoff Analysis, Customer with Modest Load Reduction

Customer with modest load reduction	80% CBL	90% CBL	100% CBL	Shopping Credit
1821 class average rate (¢/kWh)	2.599	2.599	2.599	2.599
Historical monthly consumption (MWh)	10,000	10,000	10,000	10,000
New monthly consumption (MWh)	8,000	8,000	8,000	8,000
Tier 1 (lower tier), MWh up to:	**8,000**	**9,000**	**10,000**	**10,000**
Tier 1 monthly consumption (MWh)	8,000	8,000	8,000	10,000
Tier 1 rate (¢/kWh)	1.699	2.199	2.599	2.599
Tier 1 monthly bill	$135,900	$175,911	$207,920	$259,900
Tier 2 (upper tier), MWh greater than:	**8,000**	**9,000**	**10,000**	**10,000**
Tier 2 monthly consumption (MWh)	-	-	-	-
Tier 2 rate (¢/kWh)	6.200	6.200	6.200	6.200
Tier 2 monthly bill	$0	$0	$0	$0
Tier 2 Shopping Credit, MWh less than:	**8,000**	**9,000**	**10,000**	**10,000**
Shopping credit quantity (MWh)	-	-	-	(2,000)
Shopping credit rate (¢/kWh)	-	-	-	6.200
Total monthly shopping credit	-	-	-	($124,000)
Tier 1 + Tier 2 monthly bill	*$135,900*	*$175,911*	*$207,920*	*$135,900*
Average rate for all consumption	*1.699*	*2.199*	*2.599*	*1.699*

The shopping credit approach results in the same total bill as the 80% CBL design for this customer. The shopping credit customer continues to pay BC Hydro for 10,000 MWh per month at the embedded cost rate of 2.599¢/kWh, but receives a credit for reducing consumption by 2,000 MWh at a shopping credit rate of 6.2¢/kWh (assumed here to be the same as the Tier 2 rate). The net bill is the same as under the 80% CBL design.

3.3.3 Customers with substantial reductions in energy purchases from BC Hydro

Some customers may wish to reduce their BC Hydro purchases by much more than a few percentage points. These include customers who wish to invest in self-generation, customers who wish to purchase the bulk of their energy supplies from a third-party supplier, and customers who wish to permanently close their facilities in British Columbia. In order to analyze the effect on these customers, an additional assumption is required: that a customer that does not shut down solicits an alternative source of energy for 8,000 MWh per month, while continuing to purchase 2,000 MWh per month from BC Hydro. The alternative supply, likely self-generation or third-party supply, is assumed to be available at a price of 6.1¢/kWh, slightly lower than BC Hydro's Tier 2 rate.

Table 6 shows that only the shopping credit approach allows a customer to realize savings from pursuing this option. The shopping credit approach affords the customer a modest net savings of $8,000 per month, based on the difference between BC Hydro's Tier 2 rate the price of the alternative. Each of the simple tiered rate designs that lack a shopping credit, even the 80% CBL design, results in a total net bill and average rate that is more than double that under the Schedule 1821 rate.

Table 6. Tier 1 Cutoff Analysis, Customer with Substantial Load Reduction

Customer with substantial load reduction	80% CBL	90% CBL	100% CBL	Shopping Credit
1821 class average rate (¢/kWh)	2.599	2.599	2.599	2.599
Historical monthly BC Hydro purchases (MWh)	10,000	10,000	10,000	10,000
New monthly BC Hydro purchases (MWh)	2,000	2,000	2,000	2,000
Tier 1 (lower tier), MWh up to:	**8,000**	**9,000**	**10,000**	**10,000**
Tier 1 monthly consumption (MWh)	2,000	2,000	2,000	10,000
Tier 1 rate (¢/kWh)	1.699	2.199	2.599	2.599
Tier 1 monthly bill	$33,975	$43,978	$51,980	$259,900
Tier 2 (upper tier), MWh greater than:	**8,000**	**9,000**	**10,000**	**10,000**
Tier 2 monthly consumption (MWh)	-	-	-	-
Tier 2 rate (¢/kWh)	6.200	6.200	6.200	6.200
Tier 2 monthly bill	$0	$0	$0	$0
Tier 2 Shopping Credit, MWh less than:	**8,000**	**9,000**	**10,000**	**10,000**
Shopping credit quantity (MWh)	-	-	-	(8,000)
Shopping credit rate (¢/kWh)	-	-	-	6.200
Total monthly shopping credit	-	-	-	($496,000)
BC Hydro monthly bill	*$33,975*	*$43,978*	*$51,980*	*($236,100)*
Average rate for all consumption	*1.699*	*2.199*	*2.599*	*(11.805)*
Alternative Supply, MWh greater than:	**2,000**	**2,000**	**2,000**	**2,000**
Alternative supply quantity (MWh)	8,000	8,000	8,000	8,000
Alternative supply price (¢/kWh)	6.100	6.100	6.100	6.100
Alternative supply monthly bill	$488,000	$488,000	$488,000	$488,000
Total monthly bill	*$521,975*	*$531,978*	*$539,980*	*$251,900*
Average rate for all consumption	*5.220*	*5.320*	*5.400*	*2.519*

This result assumes that the customer continues to operate under alternative energy supplies, and thus incurs the costs of alternative supply. However, if the customer instead chooses to permanently close facilities in British Columbia and reduce energy consumption by 80%, the situation is somewhat different. Under this scenario, the shopping credit provides the customer with a windfall of nearly half a million dollars per month. The customer receives a net payment of $236,000 as long as it continues to receive 2,000 MWh of energy from BC Hydro. While this will not reduce BC Hydro's margin (since the shopping credit rate is assumed to be equal to the price for which BC Hydro could sell the surplus energy on the wholesale market), public policy considerations may dictate that such an outcome be avoided.[8] This would likely necessitate some form of audit or approval process for a shopping credit larger than a certain amount.

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[8] Please see Section 6, which develops scenarios to quantify this and other forms of risk.

4 Stepped Rate Design Parameter 3: design of Tier 2 rate

Traditional utility rates are based on embedded costs of service and seek to equitably recover prudently incurred utility costs. Utility capital investments, including a rate of return, are incorporated into retail rates that stay fixed between rate cases. The stepped rate design proposed in the Energy Plan has a very different purpose: to help the utility avoid incurring *future* costs through efficient pricing. This shifting of the focus of utility rates from cost recovery to influencing customer behavior requires a Tier 2 rate that fully collects the cost of serving incremental load.

While the concept is simple, in practice there is no single method that perfectly reflects BC Hydro's incremental cost of new supply. Moreover, if the Tier 2 rate is to have the desired effect on customer behavior, the price signal must be accurate, and cost recovery must be contemporaneous. There are at least two methodologies that could be employed to develop a meaningful Tier 2 rate.

4.1 Long-term estimate of the cost of new supply

The first methodology is long-run incremental cost (LRIC), the per kWh cost of supply from a hypothetical new resource. This methodology is an appropriate estimator of the cost of procuring supply over the very long term, e.g., 10-20 years. This methodology would likely involve a BCUC process, where BC Hydro, customers and other interveners present evidence of the per kWh cost of owning and operating a new power plant. Such evidence would include capital and installation costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, and fuel price forecasts.

The table below shows an example of an LRIC calculation based on the cost of building a new natural gas-fired, combined-cycle, combustion turbine (CCGT). Using publicly available data sources such as the California Energy Commission or the U.S. Energy Information Administration, the capital cost of a new plant is estimated to be between US$15 and US$25 per MWh, depending on assumptions about financing, plant life, depreciation, etc. As of early February 2003, the average price of 2003-2008 natural gas futures traded on the New York Mercantile Exchange (NYMEX) was US$4.14 per million British thermal units (MMBtu). Adjusting to reflect conditions in the Pacific Northwest and applying a Canadian to U.S. dollar exchange rate of 1.52 yields a Tier 2 retail energy rate of between CDN 6¢ and 8¢ per kWh.

Table 7. Sample Tier 2 rate calculation using LRIC

Item	Cost Estimate	Source
CCGT Capital and Site Costs:	US $450-550 per kW	Siting, permitting and construction costs of a CCGT power plant (California Energy Commission).
Fuel Cost:	US $4.14	Average NYMEX Henry Hub futures prices between 2003 and 2008 (as of early February, 2003). Adjusted to reflect price appropriate for Pacific Northwest.
Heat rate:	6,800 kWh per MMBtu	Specs from GE and Westinghouse (California Energy Commission).
Variable O&M:	US $2-3 per MWh	Data from units already in service (California Energy Commission).
Capacity Factor:	60-90%	Depends on customer load factor
Fixed Charge Rate:	US $15-25 per MWh	Depends on capital and depreciation assumptions.
Result: CDN 6.2 – 7.9 ¢ per kWh.		

The calculation presented in the table above is a simple example based on publicly available data, and assumes a CCGT power plant design. The appropriate technology choice would depend on the relative capital and operating costs of various resource types. If gas prices rise, other technologies may be more appropriate for the

LRIC calculation. A BCUC process would afford all parties an opportunity to discuss alternative assumptions and present their own evidence, and would result in a more detailed calculation.

The LRIC methodology is attractive because of its relative simplicity. It provides a reasonably accurate estimate of the cost of procuring large quantities of new supply over a relatively long term. However, it may not provide a very accurate estimate of the cost of procuring smaller amounts of new supply, or of procuring supply for a shorter period of time. For example, if BC Hydro wished to procure 50 MW of energy for a period of one year, it would not build or contract for a new power plant. Instead, it would likely seek to purchase a block of energy from a competitive supplier in the wholesale electricity market.

Furthermore, the Energy Plan calls for time-of-use rates that "encourage customers who can manage the timing of their electricity use to shift consumption to low-priced off-peak periods." Such activity could provide economic benefits to the province if it reflects the value that society places on energy during peak and off-peak periods. This value can vary greatly depending on weather, hydro conditions, and market conditions. For example, peak to off-peak value differences are generally highest in the summer months, when daytime loads peak in the southwestern U.S. and high-cost generators must be brought on-line to meet system peaks. They are generally lowest in the winter months, when hydro operators can purchase energy at any time of day to recharge reservoirs. BC Hydro's peak to off-peak value differences are generally higher than those indicated in the market because of the ability of the hydro system to provide storage. The volatility of the peak to off-peak value difference is also susceptible to volatility because of uncertain energy supply from hydro assets due to changing weather conditions. The unique characteristics of BC Hydro's system make it difficult to send accurate price signals to load-shifting customers.

Price signals that do not reflect the current value of peak and off-peak energy would misstate the economic benefit of load shifting, potentially leading to wasteful efforts on the part of customers. While the LRIC approach could be modified to produce time-of-use rates, these rates are unlikely to meaningfully reflect the time-sensitive value of load reductions.

4.2 Short-term estimate of the cost of new supply

A simple LRIC approach would not reflect temporal considerations that affect the value of energy to the BC Hydro system. During some seasons or years, when hydro supplies are plentiful and loads are down, the per-MWh value of a one-year, 50 MW block of peak energy will be lower than a 500 MW, 20-year LRIC-based estimate. During poor water years or when loads are high, an LRIC-based estimate may be lower than a short-term or medium-term block purchase. Hence, a methodology based on a market index or price quote would more accurately reflect the cost of shorter-term supply options than LRIC. There are at least two ways of estimating the cost of shorter-term supply:

- **Price indexes**. Standard forward products such as daily and monthly on-peak (6x16) blocks are traded at several hubs in the western interconnection, and a number of trade publications gather trade data and publish market price indexes. The Mid-Columbia (or "Mid-C") hub in central Washington is the most appropriate trading hub for the BC Hydro system. However, transmission system congestion and BC Hydro's reservoir storage mean that Mid-C prices are frequently not a good indicator of the value of energy to the BC Hydro system.

◆ **Competitive solicitations**. For forward products that are thinly or not traded, or for which reliable price quotes are not readily available, BC Hydro could obtain a market quote through a competitive solicitation process. This would both facilitate price discovery and provide a built-in mechanism for managing procurement risk, as the quote provides fixed price at which a seller is willing to supply energy to BC Hydro. BC Hydro already conducts periodic RFP processes for new power supplies to meet growing retail load. The results of such a process could be employed to develop a Tier 2 rate, with some adjustment to reflect cost differences between industrial and non-industrial load.

Both market indexes and the results of a competitive solicitation would have to be transformed into a retail rate through a number of adjustments. For example, if the delivery point is at Mid-C, the market price would have to be adjusted to reflect transmission charges, including ancillary services and real power losses, paid to the Bonneville Power Administration for delivery to the BC border. Another adjustment would reflect the load shape of the industrial customer or customers on whose behalf BC Hydro purchases the Tier 2 energy. Finally, the price might have to be adjusted to reflect particular conditions on the BC Hydro system such as transmission congestion and reservoir storage that cause the Mid-C price to diverge from the marginal value of energy to BC Hydro.

4.3 The cost of long-term rate stability

The Tier 2 rate must be based on an accurate estimate of the cost of new supply. The cost of new supply is dependent on a number of factors, including the term over which the new supply is desired. Another important factor is risk. In traditional utility ratemaking, the utility takes on price risk (due to fixed tariffs that do not reflect fluctuating market prices) and volume risk (due to varying customer consumption that the utility must meet). If the stepped rate design requires BC Hydro to lock in a Tier 2 rate at a given level for a given period of time, this rate would not be margin-neutral if it did not include a markup above the new supply cost to reflect the price and volume risk.

A Tier 2 rate for incremental consumption and shopping credit for load reduction that are fixed for a period of time can obviously differ from short-term prices at which BC Hydro transacts. This imposes on BC Hydro a financial risk that arises from the fluctuating difference between volatile short-term market prices and the fixed long-term prices in the stepped rate design. BC Hydro may be able to hedge this risk through forward purchases or sales of physical energy, through financial instruments such as derivatives, or by cross hedging against other markets. However, hedging risks in a volatile commodity market can be costly. Irrespective of the hedging technique used, margin-neutrality requires that customers who desire price stability pay for the resulting risk management costs.

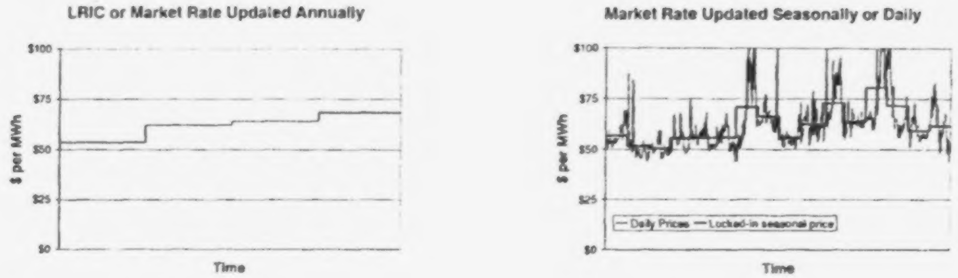
4.4 Customer perspectives on Tier 2 rate design

This section analyzes the Tier 2 design options from the perspective of different types of customers. Three broad categories of customer are considered:

- **Investing customers**. Customers who wish to make long-term investments in self-generation, energy efficiency or energy-intensive industrial processes after the implementation of the stepped rate design.
- **Load-managing customers**. Customers who have the flexibility to manage their loads in response to price signals, by shifting loads from peak to off-peak periods or from high-priced to low-priced seasons.
- **Risk-managing customers**. Customers who wish to actively manage their commodity risk, rather than have BC Hydro manage it on their behalf. Customers could manage their commodity risk by purchasing energy directly from a third-party supplier or by signing "take or pay" contracts for fixed quantities of energy from BC Hydro at a fixed price.

The principal choice of Tier 2 rate designs is between a longer-term, stable rate and a short-term, variable rate. These two choices might produce rates that look like those in the chart below. The left-hand figure represents a rate that is locked in for a long period of time, e.g., one to five years. The right-hand chart represents a rate that is updated frequently, e.g., seasonally, monthly or even daily. This rate provides price signals that reflect the value of energy in the wholesale market at any given time.

Figure 7



4.4.1 Investing customers

Customers who wish to make long-term investments would likely prefer a rate that is stable and provides a predictable, long-term return on their investments. The larger the investment and the longer the life of the facility, the more important it is to the customer to have long-term rate stability. For example, a 50 MW combustion turbine with a steam host for cogeneration would likely require an investment of at least $50 million and be amortized over 20 years. This customer would prefer a Tier 2 rate, or shopping credit, that remained stable over the 20-year period in order to ensure the investment's long-term profitability.

However, locking in a long-term rate for investing customers requires either non-investing customers or BC Hydro to assume the risk that market conditions will change. To avoid cost-shifting, the cost of assuming this risk must be part of the Tier 2 or shopping credit rate.

4.4.2 Load-managing customers

Customers who have the flexibility to manage their loads in response to time-varying price signals would prefer a Tier 2 rate in which the daily and seasonal variations are maximized. All else being equal, rates that are highly variable would allow these customers to achieve the lowest possible rates during some hours of the year, while avoiding the highest cost hours by reducing or shifting consumption. The result is an annual average rate that is lower for these customers than if the rate were flat for every hour of the year. As long as the load shifting results in corresponding reductions in BC Hydro's net cost to serve these customers, these customers are made better off through this option, while no other customers are made worse off.

4.4.3 Risk-managing customers

The stepped rate could be designed to benefit customers who are willing to commit to a particular level, shape and term of future demand or demand reductions (relative to CBL) through a more favorable Tier 2 rate. Because this commitment reduces BC Hydro's volume and price risk, it reduces the cost of the overall portfolio of energy required to serve retail customers. Under such a rate, the customer would determine the total demand for which it requires service at a Tier 2 rate (or the quantity of load reductions for which it desires a shopping credit), the shape of that demand on both a daily and a seasonal basis, and the term for which it wishes to lock in its Tier 2 rate (or shopping credit). BC Hydro would then give the customer a Tier 2 price quote for the customer's committed quantity. Because the customer's commitment has eliminated BC Hydro's volume risk, the price quote would be lower than when BC Hydro assumes the volume risk.

4.5 Stepped rate design and customer choices

The stepped rate design goal of providing incentives to change customer behavior implies that customers have the ability to make choices about how best to meet their energy needs. The Energy Plan suggests a number of choices that should be available to customers, including energy efficiency, self-generation, load management, or direct access to an alternative supplier.

Customers already have some of these choices today. Customers can choose to reduce their energy bills through energy efficiency projects, or they can invest in self-generation. However, the low rate of the existing Schedule 1821 makes most alternatives to BC Hydro supply uneconomic. The new stepped rate is intended to provide a much stronger price signal and to expand the choices that are available to customers beyond on-site projects.

In addition to behind-the-meter choices that are already available to customers, the Energy Plan requires that customers have the ability to choose a third-party energy supplier. The Energy Plan also endorses a rate design where customers can make economic choices to manage their peak loads. Finally, customers may have different preferences about the risk premiums they are willing to pay to obtain rate stability. The best way to enable customers to take advantage of these choices may be to afford customers the ability to choose among different, margin-neutral, Tier 2 rate designs.

Given a cost-free choice between rate stability and volatility, most customers would choose rates that are stable over a long period of time. However, rate stability comes at a cost, because it requires someone to assume the risk of price volatility. When the costs of risk management are added to the expected cost of energy in developing the Tier 2 rate, customers' preferences are likely to diverge. As long as the rate each customer pays reflects the true costs, including opportunity costs, associated with its choice of rate parameters, each customer choice would be margin neutral and would not affect other customers.

5 Stepped Rate Design Parameter 4: Transmission

5.1 Transmission Costs

A final rate design parameter is the treatment of transmission costs in the stepped rate design. Large industrial customers currently pay $4.411/ kVa-month on the 1821 tariff. Although this rate happens to be similar to the existing $4.53/kW-month rate paid by point-to-point wholesale customers, the 1821 demand charge is not based on the cost of transmission. Prior to the BC Transmission Company's (BCTC) development and BCUC's approval of a transmission cost for industrial customers, the transmission component of the stepped rate design must use a "transmission charge" proxy based on either the WTS rate or the demand charge from the 1821 tariff.

Under the 1821 tariff, transmission costs are allocated to customers through a demand charge of $4.411/kVa-month. The customer's billing demand is the maximum of (a) metered demand in the billing period, (b) 75% of the past highest billing demand in the immediately preceding period of November to February, or (c) 50% of the contract demand. Under the point-to-point WTS tariff, wholesale customers pay $4.53/kW-month. A WTS customer's billing demand is the maximum of the sum of its non-coincident injections or withdrawals on the transmission system. Both the 1821 tariff and the WTS rate use customers' non-coincident peak demand (NCP) to define the billing determinant.

5.2 Two options for transmission charge under stepped rate design

There are two choices for how to treat transmission costs under a stepped rate. Option 1 would continue today's system by charging customers the 1821 demand charge for their billing demand taken from BC Hydro. A variant of Option 1 is to continue to bill customers at Schedule 1821 demand charge for their baseline usage, and bill or credit them for the WTS rate for incremental changes in usage. Both versions of Option 1 have the advantage of preserving the sharing of costs that are in place today and ensuring that all customers make the same per-MW contribution to the embedded costs of the BC Hydro transmission system

Option 2 would effectively freeze the customer's transmission contribution at the existing CBL level and price any demand changes at the incremental costs to the BC Hydro transmission system. Customers would pay the same fixed charge regardless of their load. This option sends a price signal for marginal consumption decisions that is closer to the actual incremental cost to BC Hydro, which in most cases is near zero[9].

Both options are revenue neutral if the customer's billing demand does not change. Option 1 would continue to assess growing customers an increased share of the transmission costs, while allowing conserving customers to reduce their demand charge as well as their energy bills. Option 2 would keep demand charges largely the same regardless of changes in customers' share of transmission costs. However, the difference between the options is small as long as the customer's billing demand does not change substantially. Thus, customers who intend to remain with BC Hydro may be largely indifferent to the choice of a transmission rate, unless they plan to either substantially increase or decrease their loads.

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[9] During times of peak load, the marginal cost is not zero, particularly for some locations such as Vancouver Island and the Lower Mainland.

However, the options will have very different impacts on self-generation or direct access customers. Option 1 would allow self-generating customers to substantially reduce their demand charge if the customer-owned generator was reliable, while Option 2 would not change the demand charge. For a direct-access customer, Option 1 would result in a total demand charge that was very close to what the customer pays today under 1821. However, Option 2 would effectively overcharge a direct access customer, allowing BC Hydro to collect a full share of transmission costs from the customer through the demand charge in the bundled rate, as well as a transmission payment from its third-party energy supplier through WTS.

Examples of these effects are presented in the table below for a customer with maximum monthly demand of 20 MW. These examples, for the purpose of illustration, assume that the customer's billing demand is the same as its metered demand (ignoring the minimum demand provisions in Schedule 1821).

If the customer installs a 20 MW generator and the generator does not suffer an outage, the customer's bill would be reduced by more than $1 million per year under Option 1, enough to pay a substantial portion, perhaps up to 50%, of the fixed costs of a CCGT generating station. Yet out-of-pocket savings to BC Hydro from this customer choosing self-generation are modest, in most cases limited to reduced real power losses. This raises the issue of whether such a customer should receive such a large transmission credit and avoid paying an equitable share of BC Hydro's transmission costs.

Table 8. Transmission Options for Self-generation and Direct Access Customers

	Option 1	Option 2
1821 demand charge ($/kW-mo.)	$4.411	$4.411
Monthly peak demand (MW)	20	20
1821 demand payment ($/month)	$88,220	$88,220
Self-generation customer		
Load taken from own generator, no outage case (MW)	20	20
Load remaining with BC Hydro, no outage case (MW)	0	0
Total monthly bill from BC Hydro ($/month)	*$0*	*$88,220*
Load taken from own generator, outage case (MW)	0	0
Load remaining with BC Hydro, outage case (MW)	20	20
Total monthly bill from BC Hydro ($/month)	*$88,220*	*$88,220*
Direct access customer		
Load taken from third party generator (MW)	20	20
Load remaining with BC Hydro (MW)	0	0
Direct monthly bill from BC Hydro ($/month)	$0	$88,220
WTS service taken from BC Hydro by supplier (MW)	20	20
WTS tariff rate	$4.266	$4.266
Indirect bill due to BC Hydro ($/month)	$85,320	$85,320
Total monthly bill from BC Hydro ($/month)	*$85,320*	*$173,540*

On the other hand, when the customer's generator is not operating, whether due to planned maintenance or unplanned facility outage, the customer will likely draw replacement power from the BC Hydro grid. Because the billing determinant for the 1821 demand charge is the customer's highest demand during the month (its non-coincident peak or NCP demand), a single outage will trigger payment of a demand charge for the entire month. Thus, the effect on a self-generating customer is a function of the reliability of the customer's generating facility. For each month that the customer does not draw power from the grid, it saves $88,000 in transmission costs.

A full direct access customer can also reduce its demand payment to BC Hydro to zero under Option 1. However, a direct access customer is served by a third-party supplier that must take transmission service from BC Hydro under the WTS tariff. The customer will either pay for transmission service directly, or the supplier will pay for transmission service and likely pass these costs through to the retail customer. Because the WTS rate is similar to the 1821 demand charge, Option 1 is largely margin neutral for a direct access customer. Under Option 2, however, the direct access customer over pays for transmission: directly to BC Hydro through an 1821 demand charge and indirectly through the WTS bill of its supplier. This would be a substantial disincentive to choosing direct access.

5.3 Potential modifications to meet rate design objectives

These examples show that Option 2 would require modification if it is to meet the rate design objective of neutrality with respect to customer choice of supplier. Such modification need not be complex. If Option 2 were implemented, it would be relatively easy to identify direct access customers and grant them a credit against the WTS charges paid by suppliers. The third-party supplier would likely take point-to-point (PTP) service under WTS, in which case a credit based on the PTP rate multiplied by the customer's monthly peak demand would do a reasonable job of keeping the customer whole. Such credits would presumably not be available to customers who choose self-generation or energy efficiency under Option 2 (or else BC Hydro might just as well have implemented Option 1).

Option 1 does not appear to suffer the same disadvantage with respect to direct access customers, but further inquiry might be useful into the issue of the appropriate monthly billing determinant for self-generating customers. Absent the minimum demand provisions in Schedule 1821, a self-generating customer would pay no demand charge for each month in which the generator met the customer's entire needs, but would pay a bill based on peak demand for each month in which an outage occurs. Thus, the customer's average demand charge would be a function of the probability of an outage occurring in a given month. If this probability is 30%, based on an expected 70% availability rate, the above customer's bill over time would average around $26,000, or 30% * $88,000.

However, the bill would be highly variable; on an annual basis, the customer could expect to pay anywhere between nothing and $1.06 million. This may require the customer to incur some carrying costs. Moreover, the NCP billing determinant definition would give incentives that might lead to sub-optimal use of the generator. For example, a customer might delay needed maintenance until the first day of a month so as to avoid a demand charge in the previous month, raising the risk that a more serious problem will occur that leads to a lengthier outage. For these reasons, it might be preferable to develop a monthly demand charge based on an expected outage rate, and revisit the charge from time to time if actual performance varies substantially from expected performance.

Prior to re-determination of WTS and the ancillary services contained within the WTS tariff, the use of the 1821 demand charge as a transmission charge proxy (under Option 1) is probably the easiest to implement. It avoids redefining ancillary services under WTS and allows BC Hydro and other suppliers to provide prices for all incremental usage that reflect the specific energy and capacity requirements of any customer's change in incremental consumption.

6 Stepped Rate Risks

Although the stepped rate has a significant number of positive attributes, it also has the potential to be a very costly and short-lived rate experiment. This can be prevented if the stepped rates are designed to be at least margin neutral, on a risk-adjusted basis. In other words, the rates structures, levels and access rules need to either mitigate or account directly for any incremental quantity or price risk associated with the stepped rate itself or with changes in customer behavior induced by the stepped rate.

This section summarizes several risk factors in a stepped rate design. The major risk factors addressed here include market risks due to price and volume fluctuations, the risk of basing a Tier 2 rate on a market index that does not accurately reflect BC Hydro's true opportunity costs, and risks from granting customers choices among various rate designs. The potential magnitudes of each risk are quantified in a "worst case" scenario that we believe is unlikely, but possible if precautions are not taken in design and implementation. More importantly, however, the worst case scenarios motivate the need to develop a series of access principles that go hand in hand with each of the proposed stepped rate designs. These principles are described in more detail in the last 2 subsections of this report (7.5 and 7.6). The financial risk can be limited if the stepped rates can accomplish two goals:

1. Prices paid and charged to customers for incremental changes in consumption must account for risk and reflect BC Hydro's opportunity costs.
2. Access rules and rate designs must prevent unintended arbitrage between stepped rate options, between the stepped rates and market prices, and

between any other rate schedules offered by BC Hydro and the stepped rates.

6.1 Market Risks

Under both the existing 1821 schedule and the new stepped rate design, BC Hydro is obligated to sell unpredictable volumes of energy to industrial customers at fixed prices. This presents two major risks to BC Hydro: market price risk and volume risk.

Market price risk is the risk that wholesale market prices will be different from those anticipated in the fixed retail tariff. The fixed rate is a blend of BC Hydro's cost to produce and buy energy, and will change over time. Volume risk is the risk customers will consume an amount different from what BC Hydro expects, requiring BC Hydro to procure additional supplies or liquidate surplus supplies in the wholesale markets at short-term market prices which, again, often deviate from BC Hydro's fixed tariffs. The risk of over- or under-collection of revenue requirements is a function of both volume and price risk because revenue is the *product* of price and volume. As the divergence between actual and expected volumes increases, the amount of short-term energy transacted in wholesale markets increases, magnifying the effects of price risk.

The potential size of this risk can be substantial. The following analysis provides an estimate of the market risk BC Hydro could face under a worst case scenario:

- BC Hydro locks in a shopping credit rate for the twelve-month period from November 2001 to October 2002.

- The shopping credit rate is based on the average market price from November 2000 to October 2001, or CDN $269/MWh (based on actual market prices at the Mid-Columbia trading hub, as published in Megawatt Daily).
- Industrial load reduction priced at the shopping credit rate is assumed to be 20% of total industrial sector load, or 2,900 GWh.
- BC Hydro re-sells this 2,900 GWh at the daily market price, which averages CDN $31/MWh for the twelve-month period (again based on Mid-C market prices from Megawatt Daily).
- The result is an under-collection of $700 million, or approximately 25% of BC Hydro's annual revenues.

This is an exceedingly unlikely case, for a number of reasons. First, the scenario assumes that BC Hydro takes no steps to hedge itself against the possibility that market prices could fall from the historically high levels of 2001. Second, this crude analysis assumes that the process for setting the stepped rate is backward-looking, taking no advantage of the fact that, by November 2001, changing supply and demand conditions had already caused market prices to retreat to historic levels. Finally, these high prices were the product of a unique set of circumstances that are unlikely to repeat themselves. Still, this example points out the critical need for comprehensive risk management policies if the stepped rate design requires BC Hydro to lock in a Tier 2 rate or shopping credit for a period as long as one year.

It is important to note that price risk and volume risk are not endemic to the stepped rate structure alone. These risks already exist under the 1821 rate. However, by providing substantial incentives for customers to reduce their purchases from BC Hydro, the introduction of the stepped rate design may involve incremental risks for BC Hydro.

6.2 Opportunity Cost Risk

Affording customers more choices can bring benefits to both participating and non-participating customers. A customer that reduces its energy purchases from BC Hydro frees up energy that BC Hydro can sell in the wholesale market, and defers the need for BC Hydro to acquire new supply. If the loss in retail revenues can be more than offset by increased trade revenues, non-participating customers may gain due to lower retail rates.

Whether a customer's choice to reduce load is beneficial to non-participating customers depends on the spread between the shopping credit rate and the resale value of energy released by the customer. Non-participating customers are held harmless if the spread is zero with a shopping credit exactly equal to BC Hydro's opportunity cost. Under zero spread, the bill credit offered by BC Hydro is exactly equal to the gain from reselling the released energy. If the spread is positive (negative), BC Hydro will gain (lose) margin that can make other customers better (worse) off via lower (higher) rates.

Figure 8

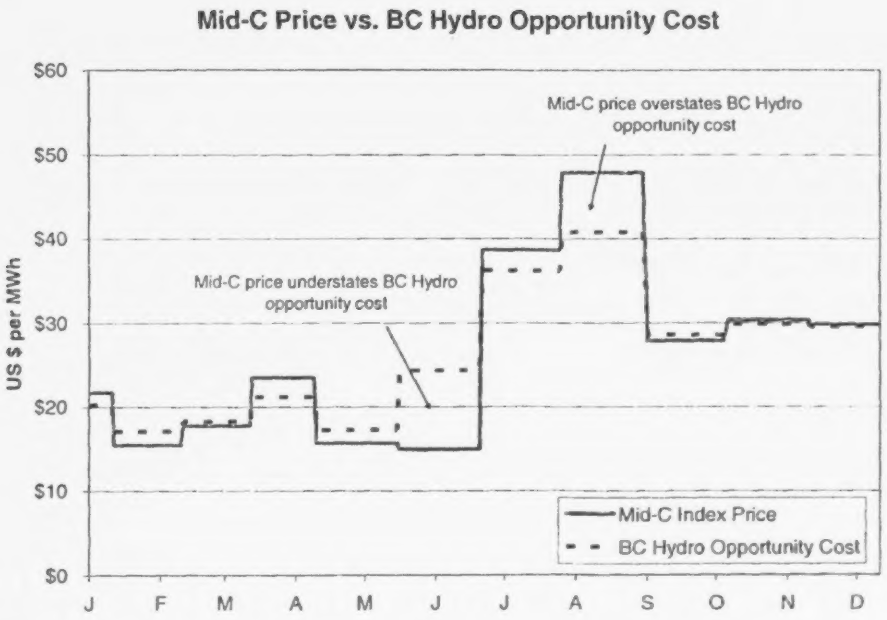


Figure 8 illustrates the risks of a Tier 2 rate pegged to the Mid-Columbia market index through a conceptual comparison of a monthly market index price to BC Hydro's opportunity costs. BC Hydro, through Powerex, generally purchases energy from the U.S. in the spring when energy prices are low to take advantage of the storage capability of large reservoirs on the Columbia and Peace River systems. Powerex then resells the energy in the U.S. during the summer months when energy prices are higher. BC Hydro's storage means that Mid-C prices understate BC Hydro's opportunity costs in the spring, and overstate them in the summer.

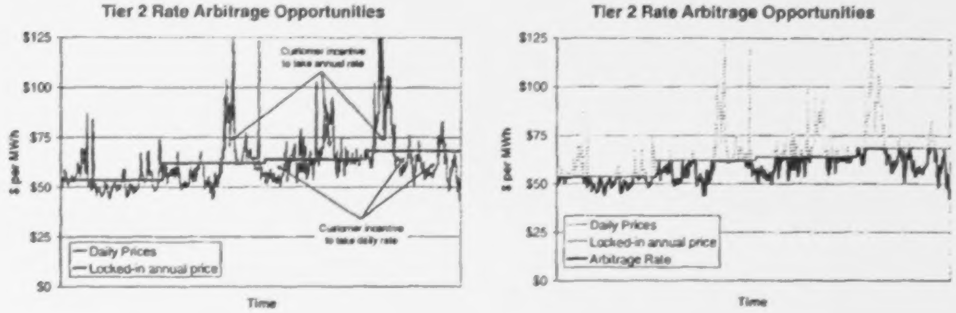
This problem is exacerbated by either minimum generation or transmission constraints that limit the amount of energy that can be delivered between the Mid-C hub and the BC Hydro system. Minimum generation constraints generally limit imports during the spring and transmission constraints limit exports during the summer. Hence, the Mid-C price will understate BC Hydro's opportunity cost during the spring, giving customers an incentive to over-consume. More importantly, the Mid-C price will overstate BC Hydro's opportunity cost during the summer, giving consumers a false signal to conserve. When the regional transmission system is constrained southbound, energy freed up by customer load reduction cannot be immediately resold at the current Mid-C price, but must be stored for later sale when the transmission system is no longer congested and Mid-C price is lower. This would reduce recovery, through trade, of revenues lost due to reduced retail sales, and most importantly, credits given to customers, potentially shifting costs to non-participating customers.

The spread between BC Hydro's opportunity costs and market prices at Mid-Columbia can be highly dynamic due to changing generation and transmission constraints, and weather conditions affecting the operation of hydro facilities. The unique characteristics of BC Hydro's system will make it difficult to develop a rate mechanism that is both simple and accurate.

6.3 Risk of arbitrage between short-term and long-term rate design choices

One possible customer choice in the stepped rate design is the choice between long-term stable rates and short-term variable rates. This choice presents a significant risk to BC Hydro if customers are allowed to freely switch back and forth between Tier 2 rate choices. If given this ability, customers will quite naturally choose short-term rates when wholesale energy prices are low and long-term rates when short-term energy prices are high. The result is a "lower-of" rate, which shifts costs or risks onto BC Hydro or other customers. The revenues received from customers can vary significantly from actual market prices during periods of high price volatility.

Figure 9

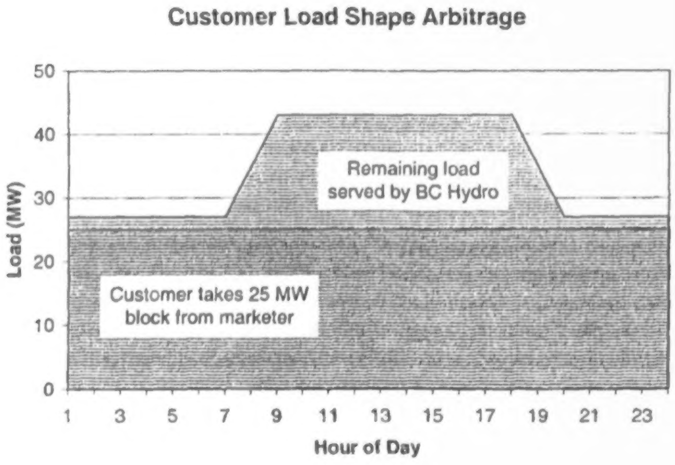


An analysis of a worst-case scenario assumes (a) customers who can always select the lower-cost choice make the low-cost decision with perfect accuracy, and (b) prices from a period of extremely high price volatility. This analysis of the worst-case scenario shows BC Hydro "opportunity losses" (difference between revenues received from customers and market prices) at over $282 million. This is almost 12% of BC Hydro's revenues of $2.45 billion in its 2002 Annual Report.

6.4 Risk of arbitrage among rate design choices based on load factor

Another source of risk to BC Hydro and non-participating customers is load shape arbitrage. Load shape arbitrage occurs when a customer takes a favorable load profile to market, leaving an unfavorable load shape to be served by BC Hydro. The customer in the chart below has chosen to obtain a 25 MW, flat (7x24) block of energy from the market. This easily supplied load is likely to attract a large number of bidders and a price more favorable than an uneven profile. However, the customer has left BC Hydro to serve a residual load that occurs almost entirely during the peak daytime hours. BC Hydro's per MWh cost to serve the customer's remaining load will be substantially higher than if it was to serve the full load. If the shopping credit this customer receives does not reflect the cost of serving the remaining load, this customer will not be paying a full share of the industrial class revenue requirement, and costs will be shifted to other customers.

Figure 10



An analysis of load factor arbitrage quantifies the possible magnitude of losses under an extreme case. The analysis assumes that customers choose, on a daily basis, whether to purchase all energy usage from BC Hydro at a Tier 2 rate that reflects the customer's actual load shape, or whether to take a flat block of energy from the market at lower rates, with the remainder being served by BC Hydro during peak hours at Tier 2 rates. Under the extreme prices that occurred in 2001, BC Hydro could lose $5 million due to load factor arbitrage. The relatively small loss is largely due to the fact that 1821 customers have high load factors and therefore relatively flat load profiles.

6.5 Risk mitigation strategies under the stepped rate design

The need for risk mitigation strategies depends on the magnitude of the risks inherent in a particular rate design. A rate design that guarantees a fixed price over a very long term exposes BC Hydro to substantial risks, thus necessitating extensive use of risk mitigation techniques. However, a rate design that continuously tracks changing market conditions (as in the case of real-time pricing) would minimize the need for such techniques.

6.5.1 Mitigating market risk

There are several methods for BC Hydro to mitigate the effects of volume and price risk:

- Fix Prices. BC Hydro can hedge price risk using fixed price contracts. These contracts include forward contracts, futures contracts, physical options or financial options. For example, if the stepped rate design's credit rate is fixed at \$C/MWh and a customer commits to cut consumption by 1000 MWh at a 100% load factor, BC Hydro can resell the same energy via a forward contract at a price \$F/MWh. The forward contract's per MWh profit is \$(F – C)/MWh and will occur with certainty.

  BC Hydro can hedge price risk for specific volumes, but changes from expected consumption levels will always leave some residual energy purchases and sales subject to price risk. Volume risk will be difficult to hedge unless new rules limiting demand changes are introduced in the stepped rates. This may be difficult given that customers can consume at any level under present 1821 rates. However, the stepped rate design may include inducements, such as preferable Tier 2 rates or shopping credits based on lower risk management costs, to encourage industrial customers to commit to fixed volumes.

Price risk management can be costly. In the above example, if the forward contract price F is less than the credit rate C, BC Hydro will suffer a per MWh loss. To eliminate this loss, the credit rate C needs to be adjusted downwards to reflect the forward market conditions. Irrespective of the hedging technique used, margin-neutrality requires that customers who desire price stability pay for the resulting risk management costs.

Finally, delivery risks exist with most hedges because the only liquid forward market close to British Columbia is Mid-Columbia. Hedging delivery risk from Mid-Columbia may be costly because BC Hydro may have to acquire firm transmission to ensure that the power can be moved from Mid-Columbia to British Columbia. The cost of hedging delivery risk must also be captured in margin-neutral Tier 2 prices.

◆ **More frequent updating of the Tier 2 rate.** The above example points to the fact that frequent updates that capture evolving market developments reduce the possible large differences between the Tier 2 rate and market prices. It also affirms that the spread between the shopping credit rate and the Tier 2 rate that compensates BC Hydro's risk assumption should be larger for a very long period than a short period.

6.5.2 Rules governing customer choices

A number of choices for customers are being contemplated in the stepped rate design. The challenge is to design a rate structure to promote choices that are beneficial and when necessary, to set rules to discourage choices that are wasteful. Generally, a Tier 2 rate that sends price signals that are more granular and precise will require fewer access rules and conditions on customer choice. A Tier 2 rate that is simple and fixed over a long period of time will require more rules and enforcement.

Mechanisms that would mitigate potential arbitrage problems include the following:

- **Appropriate allocation of risk management costs**. The cost of managing risk stemming from locking in Tier 2 rates should be allocated to the customers who choose lengthy Tier 2 rate terms. This ensures that non-participating customers and BC Hydro earnings are protected from the consequences of individual customer choices.
- **Fixed terms for rate design choice with limited sign-up period**. If customers have rate design choices, a limited sign-up period during which customers specify the term of their Tier 2 rate would help reduce arbitrage among rate design choices. The minimum term should be twelve months, and terms should be multiples of twelve months, to prevent arbitrage opportunities based on seasonal price differences.
- **Shopping credit that reflects appropriate load profile**. Customers who take only a portion of their load to market should receive a shopping credit based on the profile of their residual load served by BC Hydro. There are a number of ways this shifting of the load profile could be reflected in an

appropriate shopping credit. For instance, the shopping credit could be calculated as the difference between the total cost of serving the customer's initial load profile and the total cost of serving the residual load profile.

- **Balancing energy charges for direct access customers**. Direct access customers have a conduit to the wholesale energy market, thus giving them an opportunity to purchase energy from BC Hydro for resale on the wholesale market, while purchasing energy for domestic consumption from a third-party supplier. These customers are in effect arbitraging differences between the market price and the shopping credit rate. One solution is to require direct access customers, or their suppliers, to submit "balanced schedules" (i.e., supply equals demand) during the pre-schedule period. Deviations from the prescheduled amounts would be priced at a new balancing energy rate. This rate would reflect BC Hydro's opportunity cost and would be updated at least twice daily, perhaps even hourly. Another option is to allow customers to change their usage but to impose either physical or financial limitations (penalties) for large energy imbalances.
- **Shopping credit limitations absent verification of beneficial investment**. This would help to ensure that customers are not able to receive a shopping credit for permanently closing productive facilities.

Strong consideration should be given to supplementing these mechanisms with additional limits in participation so as to provide another layer of safeguards against unexpected outcomes. For example, a global limit could be placed on shopping credit eligibility during the first year. The limit could be set at 5% of industrial class energy sales. Higher limits could be phased in over time as any initial problems in the rate design are worked out. Alternatively, the initial term of any Tier 2 rate choice could be limited to one year until the rate design is thoroughly tested. However, this might result in a delay in customer investment projects that require greater certainty as to future Tier 2 rates.

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Ren Orans

Professional Experience

ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3) — **SAN FRANCISCO, CA**
President — **1993 - Present**

Dr. Orans founded this consulting firm in 1993. The firm has three main practice areas: Litigation support, Utility planning and Business restructuring. The firm has nationally recognized experts in the fields of transmission and distribution planning, economic and regulatory theory and finance. Dr. Orans heads the Litigation support and utility planning practices for E3.

Dr. Orans' work in utility planning is centered on the design and use of area and time-specific costs for electric utilities. The first successful application was conducted for Pacific Gas and Electric Company in their 1993 General Rate Case. Using costs developed by Dr. Orans, PG&E became the first electric utility to use area and time specific costing in its ratemaking process. This seminal work led to detailed area costing applications in pricing, marketing and planning for Wisconsin Electric Company, Niagara Mohawk Power Company, Public Service of Indiana, Kansas City Power and Light, Central and Southwest Utilities, Central Power and Light, Philadelphia Electric Company, Tennessee Valley Authority and Ontario Hydro.

Dr. Orans expertise in utility planning is complimented by his practical working experience at Pacific Gas and Electric Company, where he was responsible for designing their electric utility rates between 1981 to 1985. He has relied on this background along with his published papers to provide recent expert testimony on transmission pricing on behalf of BC Hydro (1996 and 1997), Ontario Power Generation (2000) and Hydro Quebec (2001). Dr. Orans has also recently testified in stranded asset cases before the British Columbia Utilities Commission and the Texas PUC on behalf of BC Hydro and Central Power and Light, respectively. He is currently representing the Canadians in their negotiations with other members of RTO West.

DEPARTMENT OF ENERGY, NATIONAL ENERGY RENEWABLE LABORATORY, ELECTRIC POWER RESEARCH INSTITUTE — **WASHINGTON, DC**
Lead Consultant — **1992 – 1993**

Developed new models to evaluate small-scale generation and DSM placed optimally in utility transmission and distribution systems.

PACIFIC GAS AND ELECTRIC CO. - RESEARCH AND DEVELOPMENT DEPT. — **SAN FRANCISCO, CA**
1989 – 1991

Developed an economic evaluation method for distributed generation alternatives. The new approach shows that targeted, circuit-specific, localized generation packages or targeted DSM can be less costly than larger central generation alternatives. Developed the evaluation methodology that led to PG&E's installation of a 500KW PV facility at their Kerman substation. This is the only PV ever designed to defer the need for distribution capacity.

ELECTRIC POWER RESEARCH INSTITUTE — **PALO ALTO, CA**
1988 – 1992

Developed the first formal economic model capable of integrating DSM into a transmission and distribution plan; the case study plan was used by PG&E for a $16 million pilot project that was featured on national television.

DEPARTMENT OF ENERGY **WASHINGTON, DC**
1989 – 1990

Lead consultant on a cooperative research and development project with the People's Republic of China. The final product was a book on lessons learned from electric utility costing and planning in the United States.

PACIFIC GAS AND ELECTRIC COMPANY -CORPORATE PLANNING DEPT. **SAN FRANCISCO, CA**
1987 – 1992

Lead consultant on a joint EPRI and PG&E research project to develop geographic differences in PG&E's cost-of-service for use in the evaluation of capital projects. Developed shared savings DSM incentive mechanisms for the California Collaborative.

PACIFIC GAS AND ELECTRIC COMPANY **SAN FRANCISCO, CA**
Rate Department Economist 1981 – 1985

Responsible for the technical quality of the testimony for all electric rate design filings. Developed the policy and rates for collecting more than $5.5 billion per year from nearly 3.5 million customers. Also responsible for research on customers' behavioral response to conservation and load management programs. The research led to the design and implementation of the largest residential time-of-use program in California and a variety of DSM programs.

Education

STANFORD UNIVERSITY **PALO ALTO, CA**

Ph.D. in Civil Engineering , Specialization in utility costing and pricing. 1989
MS in Engineering, Specialization in water and energy. 1987

UNIVERSITY OF CALIFORNIA AT BERKELEY **BERKELEY, CA**

BA in Economics, Concentration in applied microeconomics. 1981

Publications and Reports

Refereed Papers

Orans, R., Olson, A., Opatrny, C., Market Power Mitigation and Energy Limited Resources, Electricity Journal, March, 2003.

Chow, R.F., Horii, B., Orans, R. et. al. (1995), Local Integrated Resource Planning of a Large Load Supply System, Canadian Electrical Association.

Feinstein, C., Orans, R. (1995) "The Distributed Utility Concept," The Annual Energy Review,1988.

Woo, C.K., R. Orans, B. Horii and P. Chow (1995), "Pareto-Superior Time-of-Use Rate Options for Industrial Firms," Economics Letters.

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Orans, R., C.K. Woo and B. Horii (1994), "Targeting Demand Side Management for Electricity Transmission and Distribution Benefits," Managerial and Decision Economics, 15, 169-175.

Orans, R., C.K. Woo and R.L. Pupp (1994), "Demand Side Management and Electric Power Exchange," Energy - The International Journal, 19:1, 63-66.

Orans, R., Seeto, D., and Fairchild, W., (1985), "The Evolution of TOU Rates," Pergamon Press

Research Reports

Orans, R., C.K. Woo and B. Horii (1995), Impact of Market Structure and Pricing Options on Customers' Bills, Report submitted to B.C. Hydro.

Horii, B., Orans, R., Woo, C.K., (1994) Marginal Cost Disaggregation Study, Report submitted to PSI Energy.

Woo, C.K., L. Woo and R. Orans (1995), Rationing and Area-Specific Generation Costs, Report submitted to Pacific Gas and Electric Company.

Orans, R., C.K. Woo and C. Greenwell (1994), Designing Profitable Rate Options Using Area- and Time-Specific Costs, Report No. TR-104375, Electric Power Research Institute.

Singer, J., Orans, R., Energy Efficiency Lending, A Business Opportunity for Fannie Mae, Report submitted to Fannie Mae.

Orans, R., Feinstein, C. et. al., (1993), Distributed Utility Valuation Study, submitted to the Electric Power Research Institute, the National Renewable Energy Laboratory, and PG&E.

Orans, R., Pupp, R., (1993), Menomonee Falls Case Study, Submitted to Wisconsin Electric Power Corporation.

Orans, R. and C.K. Woo (1992), Marginal Cost Disaggregation Study, Report submitted to Wisconsin Electric Power Corporation.

Orans, R., C.K. Woo, J.N. Swisher, B. Wiersma and B. Horii (1992), Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District, Report No. TR-100487, Electric Power Research Institute.

Orans, R., Swisher, J., Duane, T., (1989), Lessons Learned from U.S. Electric Utilities, Prepared for the Department of Energy for the Peoples Republic of China.

Orans, R., Area-Specific Marginal Costing for Electric Utilities: A Case Study of Transmission and Distribution Costs (1989) PhD Thesis, Stanford University.

Orans, R., (1987)The Risk of Sales Forecasts: Controllable through Indexation and Careful Disaggregation, Submitted to Stanford University and Pacific Gas and Electric Company.

Woo, C.K. and R. Orans (1983), Transferability of Other Utilities' Time of Use Experiments to PG&E's Service Schedule D-7, Pacific Gas and Electric Company Reports filed with the California Public Utilities Commission.

Conference Papers (1994 to 1997)

Martin, J., Orans, R., Knapp, K., "DG Economics and Distribution Rate Design" (2000), Western Electric Power Institute, Distributed Generation and the Utility Distribution System Conference, March 22-23, Reno, NV.

Orans, R. (1997), "Getting the Transmission Prices Right," Facilitating Cross Border Trade, New Mexico.

Orans, R. (1997), "Deregulation on the Mainland, What is Happening and What is Not, PCEA Conference, Hawaii.

Swisher, J., Orans, R., (1995), "A New Utility DSM Strategy Using Intensive Campaigns Based on Area Specific Costs," ECEEE 1995 Summer Study.

Orans, R., Greenwell, C., (1995), "Designing Profitable Rate Options Using Area and Time-Specific Costs," Prepared for EPRI, Annual DSM Review, Dallas, Texas.

Orans, R, Integrated Local Area Planning, (1995), Prepared for NELPA and presented in Calgary.

Orans, R., Local Area Planning for Profit, "Annual Review of Distributed Resource Studies," Prepared for EPRI, Lake George, New York.

Orans, R., C.K. Woo, B. Horii and R. Pupp, (1994), "Estimation and Applications of Area- and Time-Specific Marginal Capacity Costs," Proceedings: 1994 Innovative Electricity Pricing, (February 9-11, Tampa, Florida) Electric Research Power Institute, Report TR-103629, 306-315.

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C.K. Woo

Citizenship

United States

Professional Experience

ENERGY AND ENVIRONMENTAL ECONOMICS, INC. **SAN FRANCISCO, CA**
Senior Partner **1993- Present**

Dr. Woo specializes in public utility economics, applied microeconomics, and applied finance. With over 20 years of experience in the electricity industry, he has testified and prepared expert testimony for use in regulatory proceedings in California, British Columbia and Ontario. His current research interests include electricity market reform and deregulation, electricity market integration, transmission pricing, electricity market price volatility and risk management, electricity pricing and rate design. He has published 60 articles on electricity market reform and deregulation, electricity procurement, electricity pricing, integrated resource planning, value of electricity service reliability, applied microeconomics, and applied finance. Recognized by *Who's Who in America* and *Who's Who in Science and Engineering*, Dr. Woo is an associate editor of *Energy – The International Journal* for a 3-year term of 2002-2004. He is currently a member of the editorial board of *The Energy Journal* and has served as their guest editor for a special issue on electricity reliability.

DEPARTMENT OF ECONOMICS AND FINANCE, CITY UNIVERSITY OF HONG KONG **HONG KONG**
Associate professor **1991 – 1993**

Dr. Woo analyzed the economic impacts of supply shortage on consumers, resulting in a series of publications on water and electricity rationing. He also tested the specification errors of econometric models of stock returns. As a consultant, he performed marginal costing, demand-side-management evaluation and reliability planning which led to several publications on local integrated resource planning and T&D costing.

ANALYSIS GROUP, INC. **SAN FRANCISCO, CA**
Senior Associate **1987 – 1991**

Dr. Woo was responsible for applied microeconomics, outage cost estimation, reliability planning, and electricity pricing. He was the primary consultant to several utilities for outage cost estimation and reliability differentiation. His extensive publications in these two areas are widely cited by other researchers. He also performed economic analysis of mergers and acquisition with a primary focus on the anti-trust aspect of market power. The findings from this analysis were filed with both state and federal courts.

PACIFIC GAS AND ELECTRIC COMPANY – RATES DEPARTMENT **SAN FRANCISCO, CA**
Rate Economist **1985 – 1987**

Dr. Woo revamped PG&E's research on outage cost estimation whose findings appear in a special issue of *The Energy Journal* focusing on electricity reliability. He also participated in PG&E's preparation of the General Rate Cases.

SACRAMENTO MUNICIPAL UTILITIES DIST. - RESOURCE PLANNING DEPT. **SACRAMENTO, CA**
Econometrician **1984 – 1985**

Dr. Woo was responsible for demand estimation and load forecasting. The results from his study guided SMUD's resource planning.

PACIFIC GAS AND ELECTRIC COMPANY – RATES DEPARTMENT **SAN FRANCISCO, CA**
Rate Economist **1982 – 1984**

Dr. Woo was responsible for time-of-use (TOU) demand analysis and TOU pricing mandated by the CPUC. This work resulted in a performance award from PG&E and several publications.

CALIFORNIA ENERGY COMMISSION **SACRAMENTO, CA**

Research Assistant **1978 – 1982**

Mr. Woo was the primary author of the life cycle costing model used by the CEC to analyze solar energy and other DSM measures. He testified before the CPUC on the economics of solar financing.

Education

UNIVERSITY OF CALIFORNIA AT DAVIS **DAVIS, CA**

Ph.D. in Economics **1982**

QUEEN'S UNIVERSITY **KINGSTON, ONTARIO**

MA in Econometrics **1977**

CONCORDIA UNIVERSITY **MONTREAL, QUEBEC**

B.Comm. in Economics **1976**

LANGUAGES

Cantonese

Publications and Reports

Refereed

Electricity Market Reform and Deregulation

1. *Woo, C.K., M. Borden, R. Warrington and W. Cheng (2003) "Avoiding Overpriced Risk Management: Exploring the Cyber Auction Alternative" Public Utilities Fortnightly, 141:2, 30-37.*
2. *Woo, C.K., R. Karimov and I. Horowitz (2003) "Managing Electricity Procurement Cost and Risk by a Local Distribution Company," Energy Policy, forthcoming.*
3. *Woo, C.K., D. Lloyd, R. Karimov and A. Tishler (2003) "Stranded Cost Recovery in Electricity Market Reforms in the US," Energy - The International Journal, 28:1, 1-14.*
4. *Woo, C.K., D. Lloyd and A. Tishler (2002) "Electricity Market Reform Failures: UK, Norway, Alberta and California," Energy Policy, forthcoming.*
5. *Tishler, A., C.K. Woo and D. Lloyd (2002) "Reforming Israel's Electric Sector," Energy Policy, 30:4, 347-353.*
6. *Woo, C.K. (2001) "What Went Wrong in California's Electricity Market?" Energy - The International Journal, 26:8, 747-758.*
7. *Woo, C.K., I. Horowitz and K. Hoang (2001) "Cross Hedging and Forward-Contract Pricing of Electricity," Energy Economics, 23: 1-15.*
8. *Woo, C.K., I. Horowitz and K. Hoang (2001) "Cross Hedging and Value at Risk: Wholesale Electricity Forward Contracts," Advances in Investment Analysis and Portfolio Management, 8, 283-301.*
9. *Woo, C.K., D. Lloyd-Zannetti and I. Horowitz (1997) "Electricity Market Integration in the Pacific Northwest," Energy Journal, 18:3, 75-101.*

Electricity Pricing and Rate Design

1. *Woo, C. K., B. Horii and I. Horowitz (2002) "The Hopkinson Tariff Alternative to TOU Rates in the Israel Electric Corporation," Managerial and Decision Economics, 23:9-19.*
2. *Seeto, D. Q., C.K. Woo and I. Horowitz (2001) "Finessing the Unintended Outcomes of Price-Cap Adjustments: An Electric Utility Multi-Product Perspective," Energy Policy, 29:13, 1111-1118.*
3. *Hartway, R., S. Price and C.K. Woo (1999) "Smart Meters, Customer Choice and Profitable Time of Use Rate Option," Energy - The International Journal, 24, 895-903.*
4. *Woo, C. K., I. Horowitz and J. Martin (1998) "Reliability Differentiation of Electricity Transmission," Journal of Regulatory Economics, 13:277-292.*
5. *Seeto, D.Q., C. K. Woo and I. Horowitz (1997) "Time-of-Use Rates vs. Hopkinson Tariffs Redux: An Analysis of the Choice of Rate Structures in a Regulated Electricity Distribution Company, " Energy Economics, 19, 169-185.*
6. *Woo, C.K., P. Chow and I. Horowitz (1996) "Optional Real-Time Pricing of Electricity for Industrial Firms," Pacific Economic Review, 1:1, 79-92.*

7. *Horowitz, I., D.Q. Seeto and C.K. Woo (1996) "Ramsey Pricing of Electricity under Unknown Bypass Costs," Energy Journal, 17:2, 59-77.*

8. *Woo, C.K., R. Orans, B. Horii and P. Chow (1995) "Pareto-Superior Time-of-Use Rate Option for Industrial Firms," Economics Letters, 49, 267-272.*

9. *Seeto, D.Q., S.D. He and C.K. Woo (1994) "Pricing Electric Harmonics," Energy - The International Journal, 20:7, 617-621.*

10. *Woo, C.K., B. Hobbs, R. Orans, R. Pupp and B. Horii (1994) "Emission Costs, Customer Bypass and Efficient Pricing of Electricity," Energy Journal, 15:3, 43-54.*

11. *Orans, R., C.K. Woo, R. Pupp and I. Horowitz (1994) "Demand Side Management and Electric Power Exchange," Resource and Energy Economics, 16, 243-254.*

12. *Woo, C.K. (1993) "Efficient Electricity Pricing with Self-Rationing: Reply," Journal of Regulatory Economics, 5:1, 101-102.*

13. *Woo, C.K. (1992) "Optimal Electricity Pricing and Capacity Rationing," Hong Kong Economic Papers, 22, 1-6.*

14. *Woo, C.K. (1991) "Capacity Rationing and Fixed Cost Collection," Energy Journal, 12:2, 153-164.*

15. *Woo, C.K. (1990) "Efficient Electricity Pricing with Self-Rationing," Journal of Regulatory Economics, 2:1, 69-81.*

16. *Woo, C.K. (1988) "Optimal Electricity Rates and Consumption Externality," Resources and Energy, 10, 277-292.*

17. *Woo, C.K. and D.Q. Seeto (1988) "Optimal Off-Peak Incremental Sales Rate in Electricity Pricing," Energy Journal, 9:1, 93-102.*

18. *Woo, C.K. (1988) "Inefficiency of Avoided Cost Pricing of Cogenerated Power," Energy Journal 9:1, 103-113.*

19. *Woo, C.K. and N. Toyama (1986) "Service Reliability and the Optimal Interruptible Rate Option in Residential Electricity Pricing," Energy Journal, 7:3, 123-136.*

20. *Woo, C.K. (1985), "An Application of the Expenditure Function in Electricity Pricing: Optimal Residential Time-of-Use Rate Option," Energy Journal, 6:2, 89-99.*

Integrated Resource Planning

1. *Heffner, G., C.K. Woo, B. Horii and D. Lloyd-Zannetti (1998) "Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," IEEE Transactions on Power Systems, PE-493-PWRS-012-1997, 13:2, 560-567.*

2. *Forte, V.J., R. Pupp, R. Putnam and C.K. Woo (1995) "Using Customer Outage Costs in Electricity Reliability Planning," Energy - The International Journal, 20:2, 81-87.*

3. *Pupp, R., C.K.Woo, R. Orans, B. Horii and G. Heffner (1995) "Load Research and Integrated Local T&D Planning," Energy - The International Journal, 20:2, 89-94.*

4. *Woo, C.K., D. Lloyd-Zannetti, R. Orans, B. Horii and G. Heffner (1995) "Marginal Capacity Costs of Electricity Distribution and Demand for Distributed Generation," Energy Journal, 16:2, 111-130.*

5. *Woo, C.K., R. Orans, B. Horii, R. Pupp and G. Heffner (1994) "Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," Energy - The International Journal, 19:12, 1213-1218.*

6. *Orans, R., C.K. Woo and B. Horii (1994) "Targeting Demand Side Management for Electricity Transmission and Distribution Benefits," Managerial and Decision Economics, 15, 169-175.*

7. *Orans, R., C.K. Woo and R.L. Pupp (1994) "Demand Side Management and Electric Power Exchange," Energy - The International Journal, 19:1, 63-66.*

8. *Keane, D.M. and C.K. Woo (1992) "Using Customer Outage Costs to Plan Generation Reliability," Energy - The International Journal, 17:9, 823-827.*

Value of Electricity Service Reliability

1. *Woo, C.K. and R.L. Pupp (1992) "Costs of Service Disruptions to Electricity Consumers," Energy - The International Journal, 17:2, 109-126.*

2. *Woo, C.K., R.L. Pupp, R. Mango and T. Flaim (1991) "How Much Do Electricity Consumers Want to Pay for Reliability?" Energy Systems and Policy, 15, 145-159.*

3. *Hartman, R.S., M.J. Doane and C.K. Woo (1990) "Status Quo Bias in the Measurement of Value of Service," Resources and Energy, 12, 197-214.*

4. *Munasinghe, M., C.K. Woo and H.P. Chao (1988) Special Electricity Reliability Issue, Energy Journal, 9.*

5. *Goett, A.A. D. McFadden and C.K. Woo (1988) "Estimating Residential Value of Service Reliability with Market Research Data," Special Electricity Reliability Issue, Energy Journal, 9, 105-120.*

6. *Woo, C.K. and K. Train (1988) "The Cost of Electric Power Interruption to Commercial Firms," Special Electricity Reliability Issue, Energy Journal, 9, 161-172.*

7. *Doane, M.J., R.S. Hartman and C.K. Woo, (1988) "Households' Perceived Value of Electric Power Service Reliability: An Analysis of Contingent Valuation Data," Special Electricity Reliability Issue, Energy Journal, 9, 135-149.*

8. *Doane, M.J., R.S. Hartman and C.K. Woo, (1988) "Household Preferences of Interruptible Rate Options and the Revealed Value of Service Reliability," Special Electricity Reliability Issue, Energy Journal, 9, 121-134.*

9. *Keane, D.M., L.S. MacDonald and C.K. Woo (1988) "Estimating Residential Partial Outage Costs with Market Research Data," Special Electricity Reliability Issue, Energy Journal, 9, 151-159.*

Applied Microeconomics

1. *Woo, C.K. and R.H.F. Kwok (1994) "Vanity, Superstition and Auction Price," Economics Letters, 44, 389-395.*

2. *Woo, C.K. (1994) "Managing Water Supply Shortage: Interruption vs. Pricing," Journal of Public Economics, 54, 145-160.*

3. *Woo, C.K. and K.W.K. Lo (1993) "Factor Supply Interruption, Welfare Loss and Shortage Management," Resource and Energy Economics, 15, 339-352.*

4. *Woo, C.K. (1992) "Drought Management, Service Interruption and Water Pricing: Evidence from Hong Kong," Water Resources Research, 28:10, 2591-2595.*

5. *Hartman, R.S., M.J. Doane and C.K. Woo (1991) "Consumer Rationality and the Status Quo," Quarterly Journal of Economics, February, 141-162.*

6. *Woo, C.K., P. Hanser and N. Toyama (1986) "Estimating Hourly Electric Load with Generalized Least Squares Procedures," Energy Journal, 7:2, 153-170.*

7. *Woo, C.K. (1985) "Demand for Electricity of Small Nonresidential Customers under Time-of-Use Pricing," Energy Journal, 6:4, 115-127.*

8. *Woo, C.K. (1984) "A Note on Measuring Household Welfare Effects of Time-of-Use Pricing," Energy Journal, 5:3, 171-181.*

Applied Finance

1. *Wong, K.A., C.K. Woo and R.Y.K. Ho (1998) "Macroforecasting Accuracy and Gains from Stock Market Timing," Research in Finance, 16: 127-139.*

2. *Woo, C.K. and Y.L. Cheung (1996) "Specification Tests of A Market Model of Stock Returns," Advances in Quantitative Finance and Accounting, 4: 187-194.*

3. *Woo, C.K., A. Lai and Y.L. Cheung (1995) "Specification Tests of A Market Model of Asia-Pacific Stock Returns: Thailand and Hong Kong," Journal of Business Finance and Accounting, 22:3, 363-375.*

4. *Woo, C.K., Y.L. Cheung and R.Y.K. Ho (1994) "Endogeneity Bias in Beta Estimation: Thailand and Hong Kong," Pacific-Basin Finance Journal, 2, 453-461.*

5. *Ho, R.Y.K., Z. Fang and C.K. Woo (1992) "Intraday Arbitrage Opportunities and Price Behavior of Hang Seng Index Futures," The Review of Futures Markets, 11:3, 413-430.*

6. *Fang, Z. and C.K. Woo (1991) "Two Factor Model for Bond Selection," Economics Letters, 37, 417-421.*

Research Reports

1. *Woo, C.K. (2002) Rebuttal Testimony filed on the behalf of Southern California Water Company before the California Public Utilities Commission.*

2. *Woo. C.K. and D. Lloyd (2001) Stranded Cost Recovery in Electricity Market Reforms, report submitted to Israel Electric Corporation.*

3. *Woo. C.K. and D. Lloyd (2001) Assessment of the Peak Benefit Multiplier Effect: (a) Economic Theory and Statistical Specification; and (b) Theory, Estimation and Results, reports submitted to Pacific Gas and Electric Company.*

4. *Horii, B., C.K. Woo and D. Engel (2000) PY2001 Public Purpose Program Strategy and Filing Assistance: (a) A New Methodology for Cost-Effectiveness Evaluation; (b) Peak Benefit*

Evaluation; (c) Screening Methodology for Customer Energy Management Programs; and (d) Should California Ratepayers Fund Programs that Promote Consumer Purchases of Cost-Effective Energy Efficient Goods and Services? reports submitted to Pacific Gas and Electric Company.

5. *Tishler, A., C.K. Woo and D. Lloyd (2000) Reforming Israel's Electric Sector: Choices for Change, position paper submitted to Israel Electric Corporation.*
6. *Woo, C.K. and P.D. Ferguson (1999) Comments on the Ontario Energy Board Staff's Draft Electric Distribution Rate Handbook, report submitted to Ontario Energy Board on the behalf of The Upper Canada Energy Alliance.*
7. *Woo, C.K. and K. Hoang (1999) Cross Hedging and Risk Premium, report submitted to Ontario Power Generation Inc.*
8. *Woo, C.K. and B. Horii (1999) Should Israel Electric Corporation (IEC) Replace Its Industrial Time of Use Energy Rates with A Hopkinson Tariff? report prepared for IEC.*
9. *Lloyd-Zannetti D. and C.K. Woo (1997) Wheeling Charges for Transmission Service, report prepared for Israel Electric Corporation.*
10. *Lloyd-Zannetti D. and C.K. Woo (1997) Capacity Shortage and Profitable Rate Options, report prepared for Israel Electric Corporation.*
11. *Lloyd-Zannetti, D., B. Horii, J. Martin, S. Price and C.K. Woo (1996) Profitability Primer: A Guide to Profitability Analysis in the Electric Power Industry, Report No. TR-106569, Electric Power Research Institute.*
12. *Woo, C.K. (1996) Electricity Market Integration in the Western Interconnection, prepared for British Columbia Power Exchange Corporation (Powerex).*
13. *Woo, C.K. (1996) Direct Testimony, Industrial Service Options Application, prepared for B.C. Hydro.*
14. *Woo, C.K. (1996) Rebuttal Testimony Presenting an Analysis of the Use of Class-based Value of Service for Marginal Generation Capacity Costs, filed with California Public Utilities Commission for Pacific Gas Electric Company's 1996 General Rate Case.*
15. *Woo, C.K. and R. Orans (1996) Transmission: Spot Price, Reliability Differentiation and Investment, report submitted to Ontario Hydro.*
16. *Orans, R., C.K. Woo and B. Horii (1995) Impact of Market Structure and Pricing Options on Customers' Bills, report submitted to B.C. Hydro.*
17. *Woo, C.K., L. Woo and R. Orans (1995) Rationing and Area-Specific Generation Costs, report submitted to Pacific Gas and Electric Company.*
18. *Woo, C.K., D. Lloyd-Zannetti and L. Woo (1994) Using Residual Emissions Adders in Electricity Ratemaking, report submitted to Pacific Gas and Electric Company.*
19. *Orans, R., C.K. Woo and C. Greenwell (1994) Designing Profitable Rate Options Using Area- and Time-Specific Costs, Report No. TR-104375, Electric Power Research Institute.*
20. *Orans, R. and C.K. Woo (1992) Marginal Cost Disaggregation Study, report submitted to Wisconsin Electric Power Corporation.*

21. *Orans, R., C.K. Woo, J.N. Swisher, B. Wiersma and B. Horii (1992) Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District, Report No. TR-100487, Electric Power Research Institute.*

22. *Pupp, R. and C.K. Woo (1991) Integrating Customer Outage Costs in Electricity Reliability Planning, report submitted to Niagara Mohawk Power Corporation.*

23. *Woo, C.K., R.L. Pupp and D. Glyer (1991) Voluntary Interruptible Pricing Program (VIPP): An Integrated Approach to Electricity Reliability Pricing, report submitted to Niagara Mohawk Power Corporation. Also in Caves, D.W. and D. Glyer (1992), Designing an Integrated Menu of Electric Service Options, Electric Power Research Institute Report TR-100523, Appendix B.*

24. *Doane, M.J., G. McCelland, W. Schulze and C.K. Woo (1990) Industrial Outage Cost Survey, report submitted to Niagara Mohawk Power Corporation.*

25. *Doane, M.J., G. McCelland, W. Schulze and C.K. Woo (1990) Residential Outage Cost Survey, report submitted to Niagara Mohawk Power Corporation.*

26. *Doane, M.J. and C.K. Woo (1988) An Analysis of Customer Subscription to PG&E's Interruptible and Curtailable Rates, report submitted to Pacific Gas and Electric Company.*

27. *Woo, C.K. (1988) Recent Contributions to Customer Outage Cost Estimation, report submitted to Israel Models Limited.*

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2. *Seeto, D. and C.K. Woo (1995) "Time-of-Use Rates vs. Hopkinson Tariffs in Electricity Pricing," Rutgers University Advanced Workshop in Regulation and Public Utilities Economics, 8th Annual Western Conference, July 5-7, San Diego, California.*
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Citizenship

United States

Professional Experience

ENERGY AND ENVIRONMENTAL ECONOMICS, INC. — **SAN FRANCISCO, CA**

Senior Associate — **Jan 2002 - Present**

Electricity Transmission: Represent BC Hydro in RTO West process in areas of congestion management, ancillary services, and transmission pricing.

WASHINGTON OFFICE OF TRADE AND ECONOMIC DEVELOPMENT — **OLYMPIA, WA**

Senior Energy Policy Specialist — **1996– 2002**

Develop and represent state policy interests, provide information and analysis to state agencies, legislators, the governor's office, the media, and others, in the following areas:

Electricity Transmission: Lead responsibility for developing and representing agency policy interests in a variety of regional forums, with a primary focus on pricing and congestion management issues.

> **RTO West, 2000-present:** Regular participant in RTO West Congestion Management, Ancillary Services, and Transmission Planning work groups. Participate in numerous subgroups developing issues such as congestion zone definition, nature of long-term transmission rights, RTO role in transmission grid expansion, and others.
>
> **Western Market Interface Committee, 1999-present:** Participant in Western Market Interface Committee and WMIC "Seams" task force.
>
> **Western Regional Transmission Association, 1996-present:** Member, WRTA Board of Directors. Participated in WRTA Tariff, Access and Pricing Committee. Participated in sub-groups examining "seams" issues among multiple independent system operators in the West and developing a proposal for tradable firm transmission rights in the Western interconnection.
>
> **IndeGO, 1996-1998:** Regular participant in pricing, congestion management and governance committees developing Northwest independent grid operator proposal (has since evolved into RTO West).
>
> **Comprehensive Review of the Northwest Energy System, and Comprehensive Review Transition Board, 1996-1997:** Served as staff to four-state governor-appointed committee charged with developing vision for the future of the Bonneville Power Administration and the Northwest's electricity industry. Recommendations stemming from transmission work group included formation of a regional independent system operator and "FERC-equivalent" jurisdiction over BPA transmission.
>
> **Northwest Regional Transmission Association, 1996:** Participated in NRTA Pricing Committee process to develop Northwest regional transmission tariff.
>
> **Wholesale Energy Markets:** Monitor and analyze trends in electricity, natural gas and petroleum markets. Editor and principal author of Convergence: Natural Gas and Electricity in Washington, a survey of the Northwest's natural gas industry in the wake of the extreme price events of winter 2000-2001, and on the eve of a significant increase in demand due to gas-fired power plants. Authored legislative testimony on the ability of the Northwest's natural gas industry to meet the demand from new, gas-fired power plants.

Electricity Restructuring: Co-authored Washington Electricity System Study, legislatively-mandated study of Washington's electricity system in the context of ongoing trends and potential methods of electric industry restructuring. Authored legislative testimony on the impact of restructuring on retail electricity prices in Washington, electric industry restructuring and Washington's tax system, and the interactions between restructured electricity and natural gas markets.

Energy Data: Manage three-person energy data team that collects and maintains a repository of state energy data. Developed Washington's Energy Indicators, a series of policy benchmarks and key trends for Washington's energy system; second edition published in January 2001.

Energy Taxes: Lead responsibility for developing state energy policy in area of energy taxation. Co-authored Department of Revenue Study of Energy Taxation in 1999.

DECISION ANALYSIS CORPORATION OF VIRGINIA **VIENNA, VA**
Associate **1993– 1996**

Joined firm as Research Associate and was promoted to Associate after six months.

Energy Modeling and Analysis: Developed energy demand forecasting models for Energy Information Administration's National Energy Modeling System. Results are published each year in EIA's Annual Energy Outlook.

Energy Research Program Evaluation: Developed system for evaluating the potential impact of Department of Energy conservation and renewable energy research programs.

Education

UNIVERSITY OF PENNSYLVANIA **PHILADELPHIA, PA**
Institut Français Du Pètrole **PARIS, FRANCE**
M.S. IN INTERNATIONAL ENERGY MANAGEMENT AND POLICY **1993**

Collaborative Master's program focusing on the international energy industry.

Relevant Coursework: Resource economics; petroleum economics; environmental economics; energy conservation and demand-side management; energy modeling and analysis; petroleum exploration, production, refining and distribution; finance; marketing.

Special Research Topics: Energy pricing in developing countries; the economics of wind electricity generation; energy planning in Nepal; petroleum taxation in the European Community.

UNIVERSITY OF WASHINGTON **SEATTLE, WA**
B.S. IN MATHEMATICAL SCIENCE and B.S. IN STATISTICS **1990**

Publications and Reports

"Convergence: Natural Gas and Electricity in Washington", presented to the Puget Sound chapter of the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Seattle, Washington, November 14, 2001

"Convergence: Natural Gas and Electricity in Washington", presented to the Western Interstate Energy Board, Seattle, Washington, October 30, 2001

"Transmission Planning Under Regional Transmission Organizations: Issues and Priorities for Environmentalists and Residential Electricity Consumers", presented at the annual membership meeting of the Northwest Energy Coalition, Seattle, Washington, October 5, 2001

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CTED Comments on FERC ISO Policy, author. July 1998. http://www.energy.cted.wa.gov/letters/FERC-ISO.html.

CTED Comments on the IndeGO Proposal for a Northwest Independent Grid Operator, author. February 1998. http://www.energy.cted.wa.gov/LETTERS/980209.HTML.

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NEMS Transportation Sector Model: Freight Truck Stock Adjustment Model Update, author. Decision Analysis Corporation of Virginia. Prepared for Energy Information Administration, November 1995.

NEMS Transportation Sector Mass Transit Model: Proposed Model Structure, Results and Sensitivity Analysis, author. Decision Analysis Corporation of Virginia. Prepared for Energy Information Administration, August 1995.

NEMS Transportation Sector Model: Light Truck Use in Freight vs. Commercial Fleets, author. Decision Analysis Corporation of Virginia. Prepared for Energy Information Administration, February 1995.

Quality Metrics Navigation System: User's Guide, author. Decision Analysis Corporation of Virginia. Prepared for Office of Energy Efficiency and Renewable Energy, Department of Energy, October 1994.

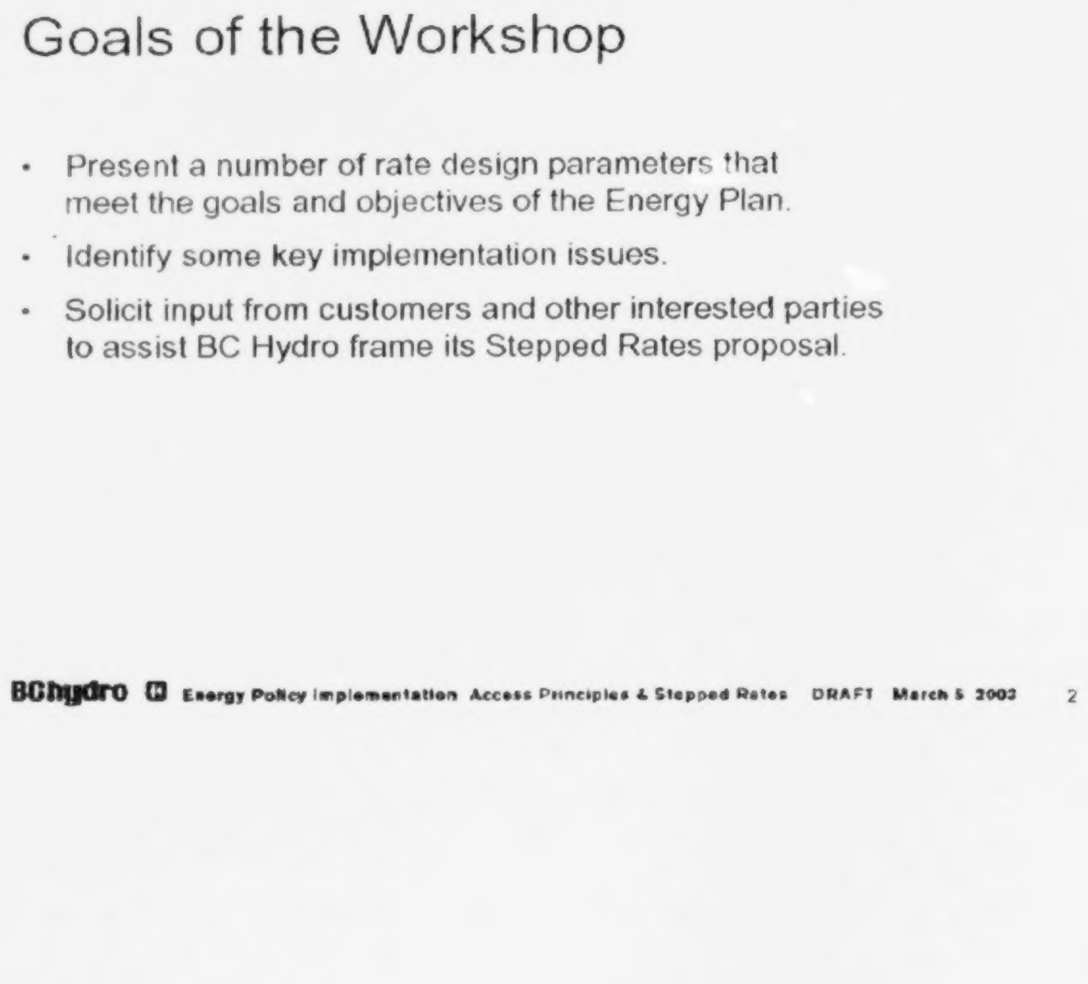
Model Documentation Report: Transportation Sector Model of the National Energy Modeling System, contributing author. Decision Analysis Corporation of Virginia. Prepared for Energy Information Administration, March 1994.

BC hydro

Energy Policy Implementation Process

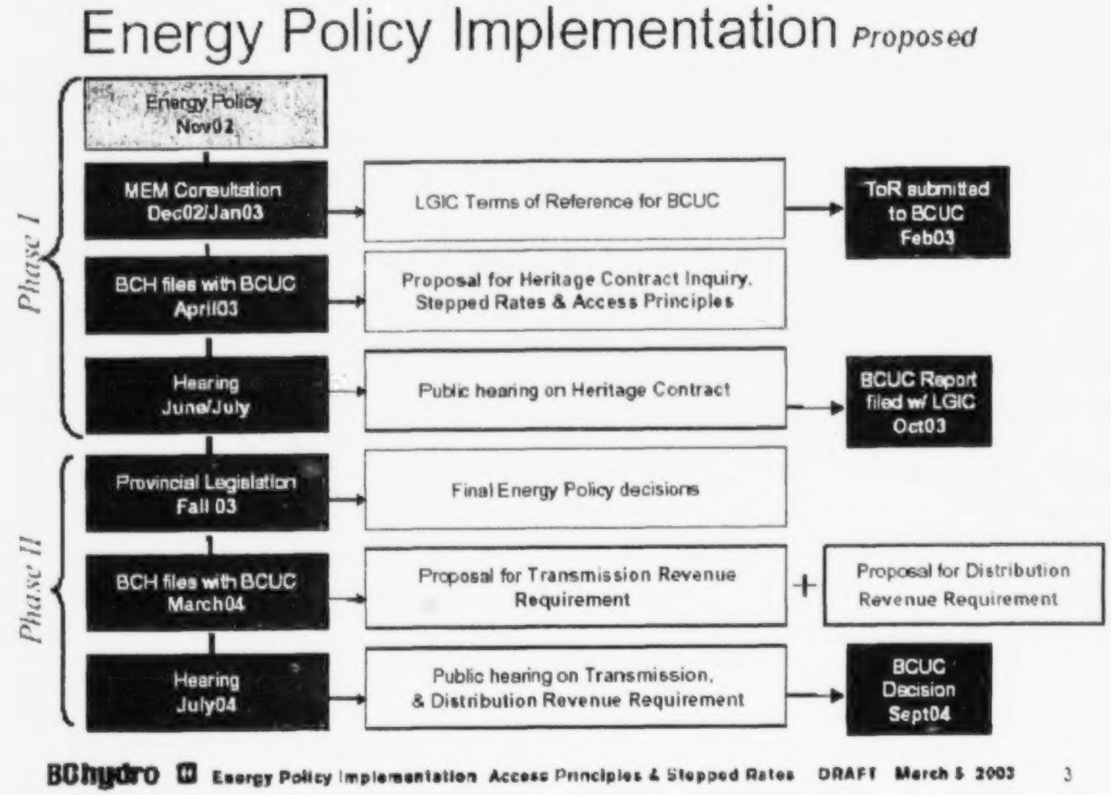
BC Hydro Information Session and Workshop on Stepped Rates and Access Principles

March 5, 2003



Goals of the Workshop

- Present a number of rate design parameters that meet the goals and objectives of the Energy Plan.
- Identify some key implementation issues.
- Solicit input from customers and other interested parties to assist BC Hydro frame its Stepped Rates proposal.



Energy Policy Implementation *Proposed*

Phase I

Energy Policy
Nov02

MEM Consultation
Dec02/Jan03 → LGIC Terms of Reference for BCUC → ToR submitted to BCUC Feb03

BCH files with BCUC
April03 → Proposal for Heritage Contract Inquiry, Stepped Rates & Access Principles

Hearing
June/July → Public hearing on Heritage Contract → BCUC Report filed w/ LGIC Oct03

Phase II

Provincial Legislation
Fall 03 → Final Energy Policy decisions

BCH files with BCUC
March04 → Proposal for Transmission Revenue Requirement + Proposal for Distribution Revenue Requirement

Hearing
July04 → Public hearing on Transmission, & Distribution Revenue Requirement → BCUC Decision Sept04

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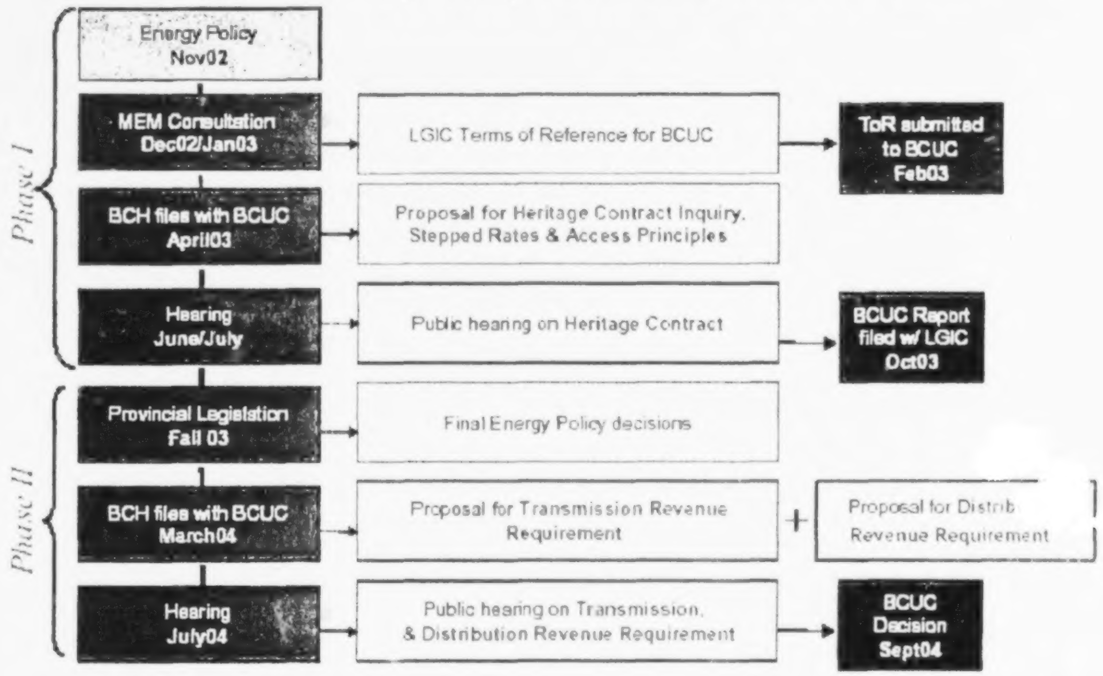
Energy Policy Implementation *Proposed*



Phase I

Energy Policy Nov02

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Phase II

Provincial Legislation Fall 03 → Final Energy Policy decisions

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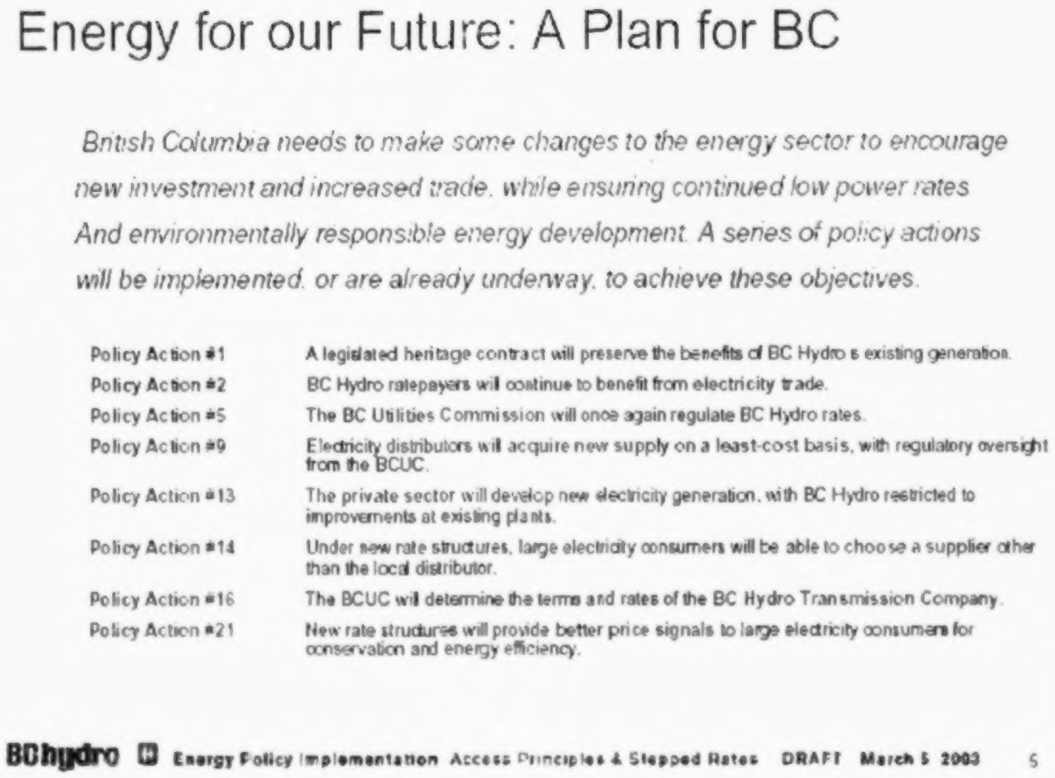
Direction from the Energy Plan



Energy for our Future: A Plan for BC

British Columbia needs to make some changes to the energy sector to encourage new investment and increased trade, while ensuring continued low power rates And environmentally responsible energy development. A series of policy actions will be implemented, or are already underway, to achieve these objectives.

Policy Action #1	A legislated heritage contract will preserve the benefits of BC Hydro's existing generation.
Policy Action #2	BC Hydro ratepayers will continue to benefit from electricity trade.
Policy Action #5	The BC Utilities Commission will once again regulate BC Hydro rates.
Policy Action #9	Electricity distributors will acquire new supply on a least-cost basis, with regulatory oversight from the BCUC.
Policy Action #13	The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.
Policy Action #14	Under new rate structures, large electricity consumers will be able to choose a supplier other than the local distributor.
Policy Action #16	The BCUC will determine the terms and rates of the BC Hydro Transmission Company.
Policy Action #21	New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.

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Energy Plan Policy Actions - a closer look

Policy Action #14: Under new rate structures, large electricity consumers will be able to choose a supplier other than the local distributor.

New stepped pricing will provide an incentive for large industrial or transmission rate customers to purchase from IPPs, or to self-generate, when they can do so less expensively than the utility's cost of new supply. These larger customers will be able to meet all or a portion of their consumption from private generation. This policy change introduces retail competition for large BC Hydro customers.

Energy Plan Policy Actions - a closer look

Policy Action #21: New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.

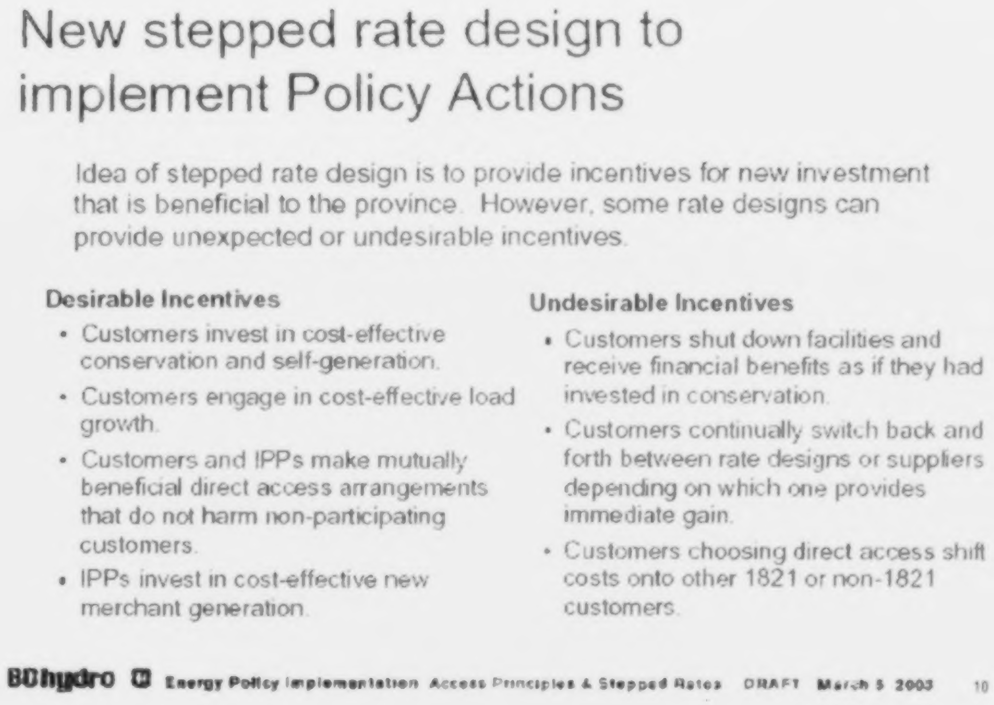
The BC Utilities Commission will conduct a hearing to develop new stepped and time-of-use pricing for BC Hydro s industrial and large commercial customers. As a principle, for stepped rates, the last block of energy consumed should reflect the cost of new supply. This will encourage these customers to meet part of their electricity needs through conservation and energy efficiency, or from other sources (self-generation or IPP purchases), where they can do so cost-effectively. To keep rates low overall, the stepped rate structure will be revenue-neutral. Time-of-use rates will encourage customers who can manage the timing of their electricity use to shift consumption to low-priced off-peak periods.

Note that our interpretation of this Policy Action is that the new stepped rate is mandatory.

Introduction to Stepped Rates and Access Principles

New stepped rate design to implement Policy Actions

- Stepped rate design marries the twin policy goals of preserving the benefits of low, 1821 rates while providing better price signals for marginal consumption decisions.
- A stepped rate design features different rates for different blocks of energy consumption. For example, consumption up to *X* MWh is priced at Tier 1 rate, consumption above *X* MWh is priced at Tier 2 rate.
- Rate designed to meet the following objectives and constraints:
  1. To preserve benefits of low-cost hydro power, the Tier 1 rate must be set at low, embedded cost (1821) rate.
  2. To provide customers with an appropriate price signal for conservation, the Tier 2 rate must be tied to an estimate of the market value of energy.
  3. To avoid shifting costs among customers, the rate design must be revenue neutral for each customer at historical consumption levels.
  4. To provide meaningful customer choices, the rate design must be neutral with respect to customer s choice of energy supplier (BCH, IPP or marketer), self-generation, or DSM.
  5. To avoid unnecessary implementation expense, the new rate design must be easy to understand and implemented with minimal regulatory process.



New stepped rate design to implement Policy Actions

Idea of stepped rate design is to provide incentives for new investment that is beneficial to the province. However, some rate designs can provide unexpected or undesirable incentives.

Desirable Incentives

- Customers invest in cost-effective conservation and self-generation.
- Customers engage in cost-effective load growth.
- Customers and IPPs make mutually beneficial direct access arrangements that do not harm non-participating customers.
- IPPs invest in cost-effective new merchant generation.

Undesirable Incentives

- Customers shut down facilities and receive financial benefits as if they had invested in conservation.
- Customers continually switch back and forth between rate designs or suppliers depending on which one provides immediate gain.
- Customers choosing direct access shift costs onto other 1821 or non-1821 customers.

New stepped rate design to implement Policy Actions

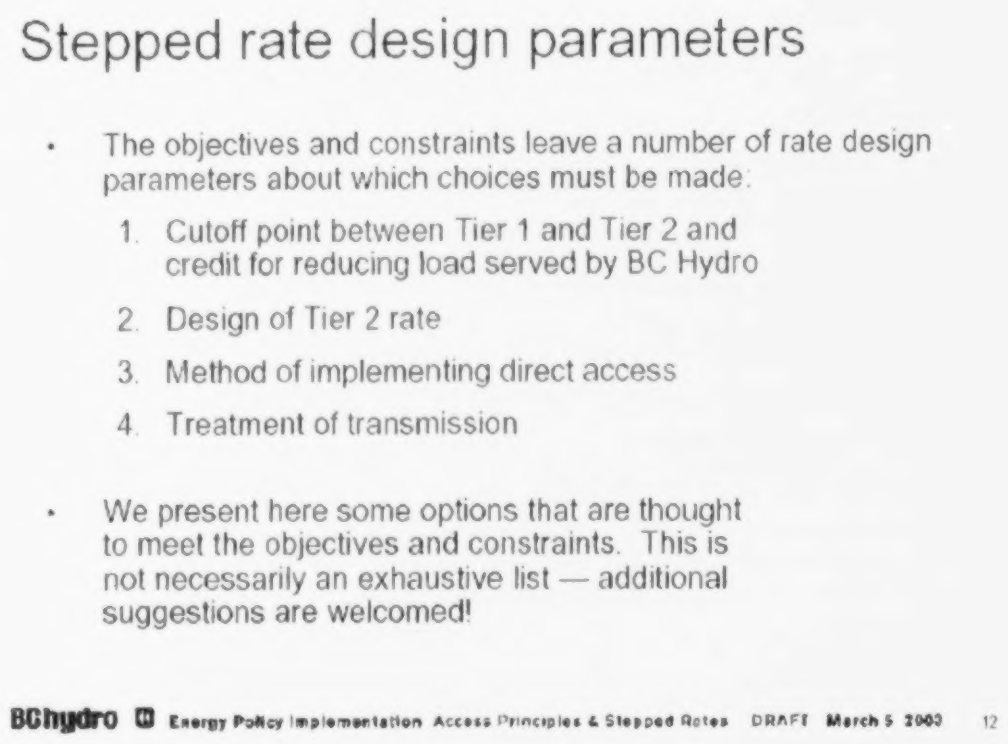
The set of objectives and constraints is fairly restrictive and circumscribes the available rate design choices.

Rate Designs that are in-bounds

- Tiered rate with Tier 1 rate applied to a fraction (e.g., 60%) of historical use
- Tiered rate with Tier 1 rate applied to 100% of historical use
- Tiered rate with Tier 2 rate set at long-run incremental cost
- Tiered rate with Tier 2 rate indexed to wholesale market prices
- Tiered rate with RTP-type mechanism that credits conservation at market prices regardless of Tier cutoffs

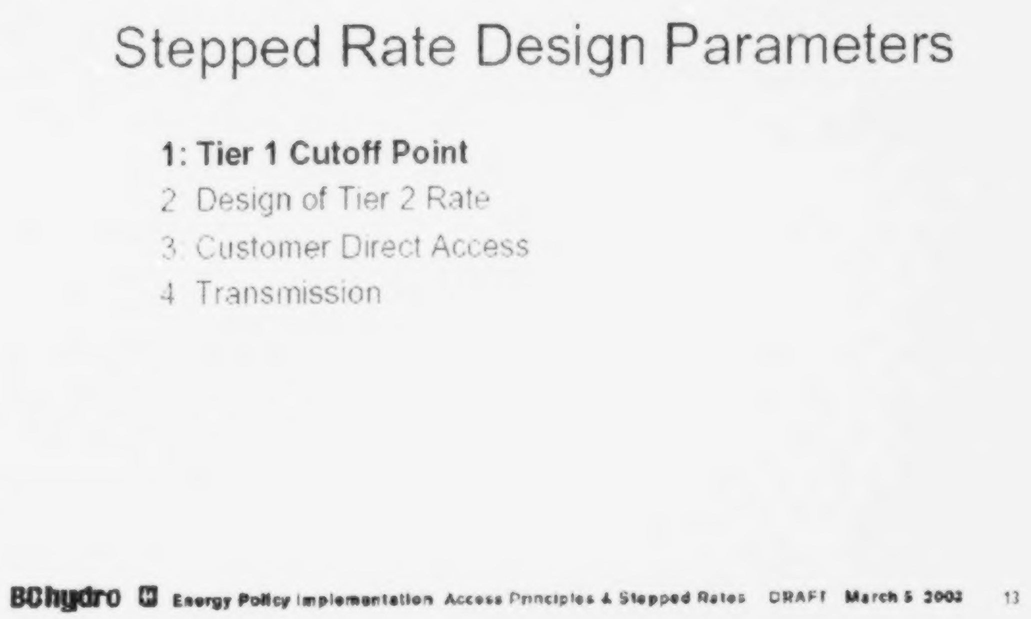
Rate Designs that are out-of-bounds

- Tier 1 rate set at market value of energy (i.e., mandatory retail restructuring)
- Tier 2 rate set lower (or higher) than market value
- Punitive entry and exit requirements that prevent meaningful retail choice
- Increased costs to other customers as a result of retail choice
- Complete redesign of 1821 rate structure
- Growing demand met at 1821 rate
- Substantial changes to WTS design



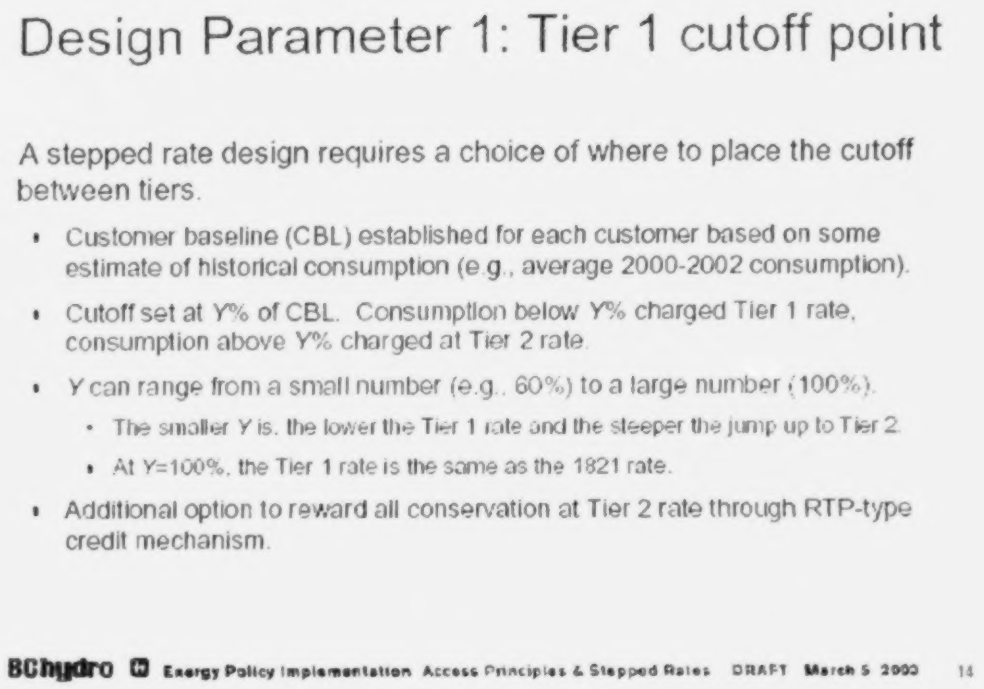
Stepped rate design parameters

- The objectives and constraints leave a number of rate design parameters about which choices must be made:
  1. Cutoff point between Tier 1 and Tier 2 and credit for reducing load served by BC Hydro
  2. Design of Tier 2 rate
  3. Method of implementing direct access
  4. Treatment of transmission
- We present here some options that are thought to meet the objectives and constraints. This is not necessarily an exhaustive list — additional suggestions are welcomed!



Stepped Rate Design Parameters

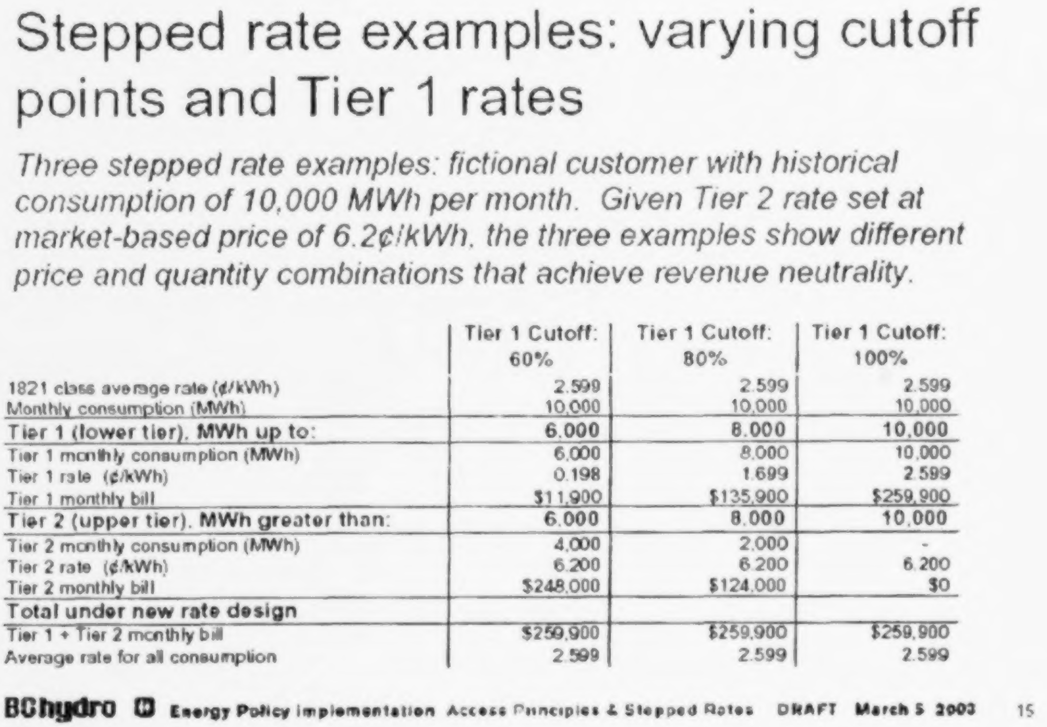
1: **Tier 1 Cutoff Point**
2: Design of Tier 2 Rate
3: Customer Direct Access
4: Transmission



Design Parameter 1: Tier 1 cutoff point

A stepped rate design requires a choice of where to place the cutoff between tiers.

- Customer baseline (CBL) established for each customer based on some estimate of historical consumption (e.g., average 2000-2002 consumption).
- Cutoff set at Y% of CBL. Consumption below Y% charged Tier 1 rate, consumption above Y% charged at Tier 2 rate.
- Y can range from a small number (e.g., 60%) to a large number (100%).
    - The smaller Y is, the lower the Tier 1 rate and the steeper the jump up to Tier 2.
    - At Y=100%, the Tier 1 rate is the same as the 1821 rate.
- Additional option to reward all conservation at Tier 2 rate through RTP-type credit mechanism.



Stepped rate examples: varying cutoff points and Tier 1 rates

Three stepped rate examples: fictional customer with historical consumption of 10,000 MWh per month. Given Tier 2 rate set at market-based price of 6.2¢/kWh, the three examples show different price and quantity combinations that achieve revenue neutrality.

	Tier 1 Cutoff: 60%	Tier 1 Cutoff: 80%	Tier 1 Cutoff: 100%
1821 class average rate (¢/kWh)	2.599	2.599	2.599
Monthly consumption (MWh)	10,000	10,000	10,000
Tier 1 (lower tier), MWh up to:	**6.000**	**8.000**	**10,000**
Tier 1 monthly consumption (MWh)	6,000	8,000	10,000
Tier 1 rate (¢/kWh)	0.198	1.699	2.599
Tier 1 monthly bill	$11,900	$135,900	$259,900
Tier 2 (upper tier), MWh greater than:	**6.000**	**8.000**	**10,000**
Tier 2 monthly consumption (MWh)	4,000	2,000	-
Tier 2 rate (¢/kWh)	6.200	6.200	6.200
Tier 2 monthly bill	$248,000	$124,000	$0
Total under new rate design			
Tier 1 + Tier 2 monthly bill	$259,900	$259,900	$259,900
Average rate for all consumption	2.599	2.599	2.599

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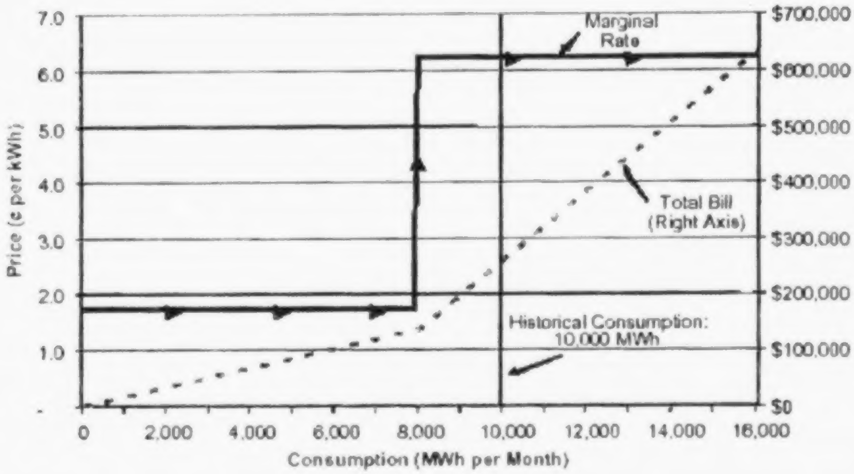
Stepped rate design illustration



Stepped rate with Tier 1 = 80% of CBL

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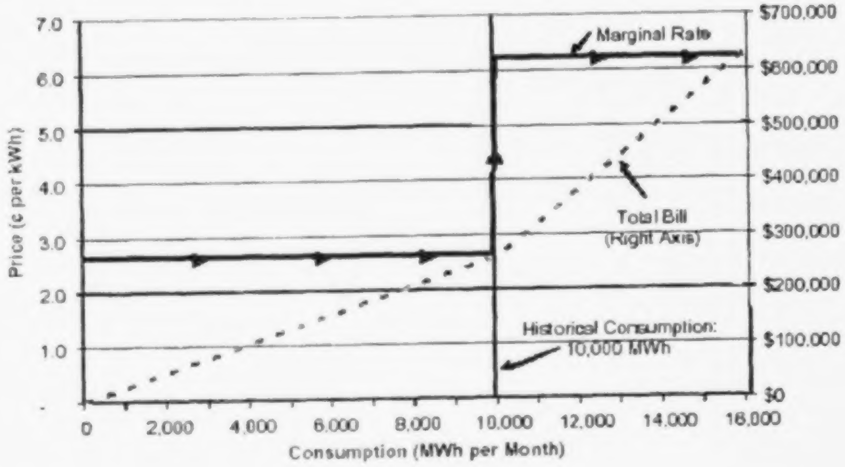
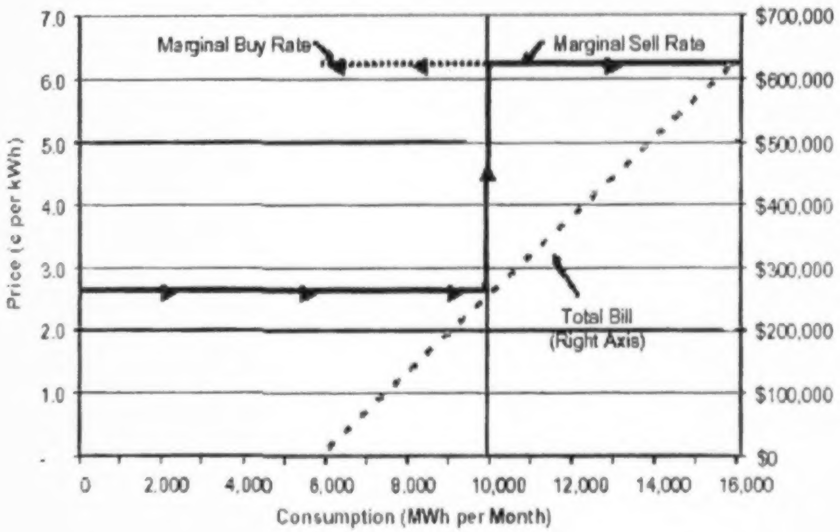
Stepped rate design illustration

Stepped rate with Tier 1 = 100% of CBL



Stepped rate design illustration



Stepped Rate With Tier 1 = 100% of CBL and RTP Credit

Customer incentives: credits for reduced consumption

- Reduced consumption can be the result of three different causes:
  1. Energy efficiency —same or greater production with less energy consumption.
  2. Self-generation —customer installs behind-the-meter generation or combined heat and power system.
  3. Partial or full shutdown — customer reduces energy consumption by reducing production.
- Economic development goals may require distinguishing (3) from (1) and (2) and reducing or eliminating the credit in case of permanent shutdown.
- This problem is self-limiting with Tier 1 < 100% of CBL; reduction below Tier 1 cutoff rewarded at Tier 1 rate.
- Under RTP credit option, there would need to be a lower limit, e.g., Z% of CBL, below which a procedure is required to determine eligibility for further credits.

Design Parameter 1: Summary

- Stepped rate design without RTP-type credit requires careful choice of Tier 1 cutoff:
  - Setting Tier 1 cutoff too low results in ridiculously low Tier 1 rate —at the extreme, Tier 1 power would be free!
  - Setting Tier 1 cutoff too high means the savings available may not be sufficient to justify large investments.
- Stepped rate design with RTP-type credit provides stronger incentives, but requires administrative safeguards:
  - Incentive to conserve, self-generate or choose direct access for entire customer load.
  - Could implement RTP-type credit regardless of choice of Tier 1 cutoff.
  - However, need limit on customer savings to avoid rewarding permanent plant shutdown.

Stepped Rate Design Parameters

1: Tier 1 Cutoff Point

2: Design of Tier 2 Rate

3: Customer Direct Access

4: Transmission

Design Parameter 2: Tier 2 rate

A stepped rate design that meets the policy objectives requires a Tier 2 rate based on an estimate of the value of energy. Two possible methodologies:

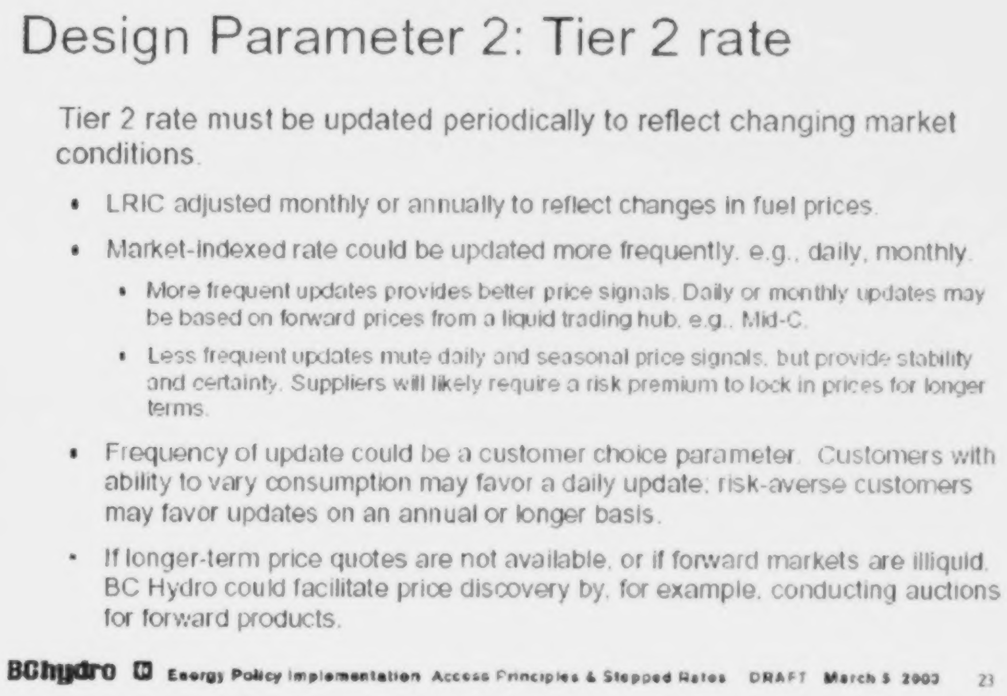
A. Based on an administrative estimate, e.g., long-run incremental cost (LRIC).

- Provides stability and predictability for customer investment.
- However, customer investments expose BC Hydro to risk, because it is forced to credit long-term load reductions at LRIC, even during times when LRIC is a poor estimate of BC Hydro's opportunity costs.
- Customer-specific rate based on customer load *factor*.

B. Indexed to wholesale market prices.

- Provides market-based price signals, leading to better short-term demand response and more efficient consumption decisions.
- However, wholesale market price volatility may discourage long-term investment.
- Customer-specific rate based on customer load *profile*.

Both methodologies require the use of access rules to prevent arbitrage and strict accounting/procurement procedures to insulate all other customers from the costs and risks of Tier 2 rates.



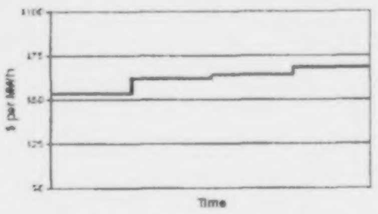
Design Parameter 2: Tier 2 rate

Tier 2 rate must be updated periodically to reflect changing market conditions.

- LRIC adjusted monthly or annually to reflect changes in fuel prices.
- Market-indexed rate could be updated more frequently, e.g., daily, monthly.
  - More frequent updates provides better price signals. Daily or monthly updates may be based on forward prices from a liquid trading hub, e.g., Mid-C.
  - Less frequent updates mute daily and seasonal price signals, but provide stability and certainty. Suppliers will likely require a risk premium to lock in prices for longer terms.
- Frequency of update could be a customer choice parameter. Customers with ability to vary consumption may favor a daily update; risk-averse customers may favor updates on an annual or longer basis.
- If longer-term price quotes are not available, or if forward markets are illiquid, BC Hydro could facilitate price discovery by, for example, conducting auctions for forward products.

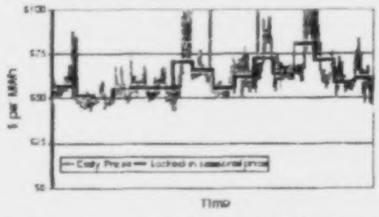
Design Parameter 2: Tier 2 rate

LRIC or Market Rate Updated Annually



- Infrequent updates provide stable, long-term price signals for investment.
- LRIC rate determined through administrative process, updated for changes in fuel prices.
- Easy to calculate and administer, however, does not provide accurate short-term price signals.
- Annual market rate probably higher than daily rate because suppliers charge risk premium to lock in prices in advance.

Market Rate Updated Seasonally or Daily



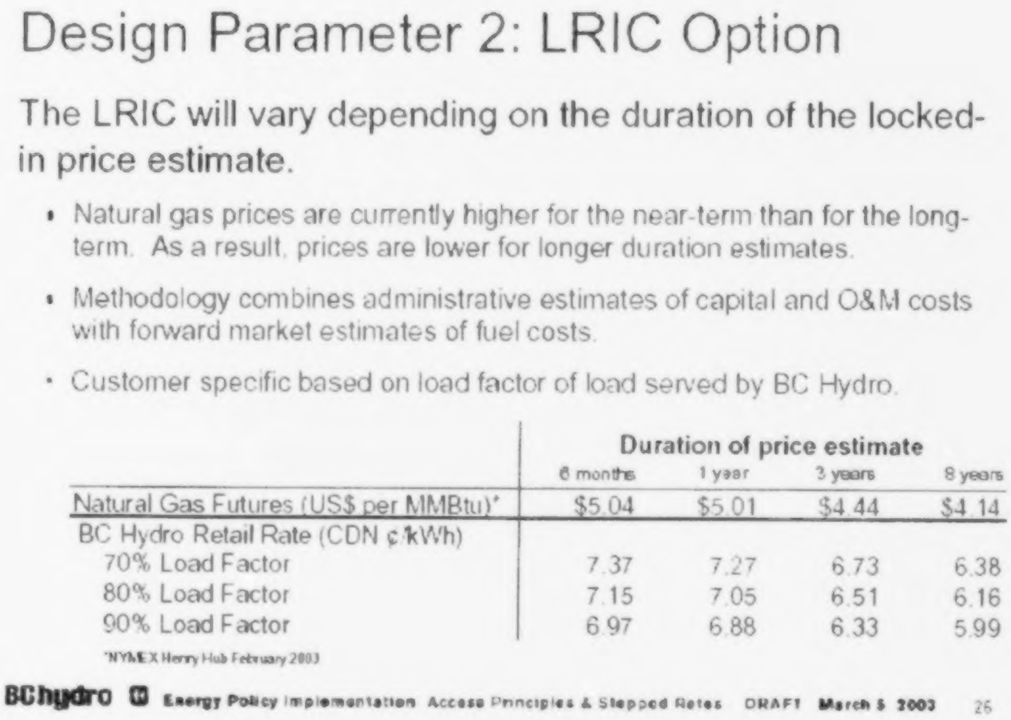
- More frequent updates provide better price signals about the current value of energy.
- Opportunity for customers who can vary their consumption to earn revenues during high-priced times.
- Customers protected from market volatility for consumption up to CBL.
- More complicated structure — based on market index, e.g., Mid-C, or auction price.

Design Parameter 2: LRIC Option

The LRIC is a calculated number based on a traditional long-run avoided cost methodology, using a hypothetical resource. For example, the LRIC could be based on the fully allocated cost of a natural gas-fired, combined-cycle, combustion turbine (CCGT).

- CCGT Capital and Site Costs: US $450-550 per kW, based on costs of CCGTs built or permitted in California.
- Fuel Cost: US $4.14 as of early February 2003, average NYMEX Henry Hub futures prices between 2003 and 2008. Adjusted to reflect price appropriate for Pacific Northwest.
- Heat rate: 6800 kWh per MMBtu, based on specs from GE and Westinghouse as reported by the California Energy Commission.
- Variable O&M: US $2-3 per MWh, based on data from units already in service as reported by the California Energy Commission.
- Capacity Factor: 60-80%, depending on customer load factor.
- Fixed Charge Rate: US $10-20 per MWh depending on capital and depreciation assumptions.

Result: CDN 6.2 — 7.9 ¢ per kWh.



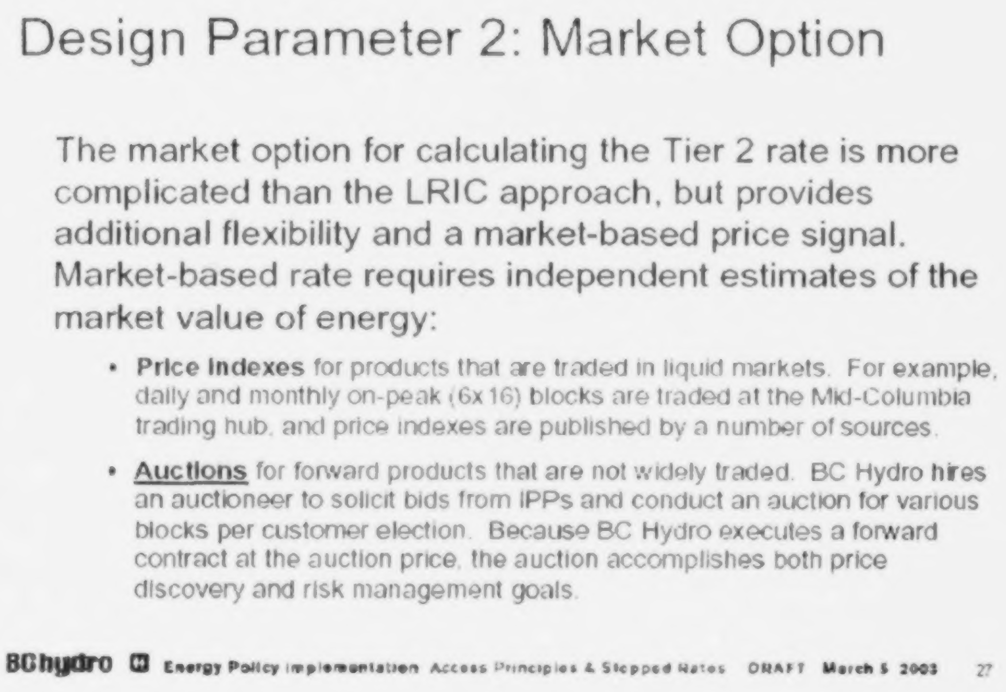
Design Parameter 2: LRIC Option

The LRIC will vary depending on the duration of the locked-in price estimate.

- Natural gas prices are currently higher for the near-term than for the long-term. As a result, prices are lower for longer duration estimates.
- Methodology combines administrative estimates of capital and O&M costs with forward market estimates of fuel costs.
- Customer specific based on load factor of load served by BC Hydro.

	Duration of price estimate			
	6 months	1 year	3 years	8 years
Natural Gas Futures (US$ per MMBtu)*	$5.04	$5.01	$4.44	$4.14
BC Hydro Retail Rate (CDN ¢/kWh)				
70% Load Factor	7.37	7.27	6.73	6.38
80% Load Factor	7.15	7.05	6.51	6.16
90% Load Factor	6.97	6.88	6.33	5.99

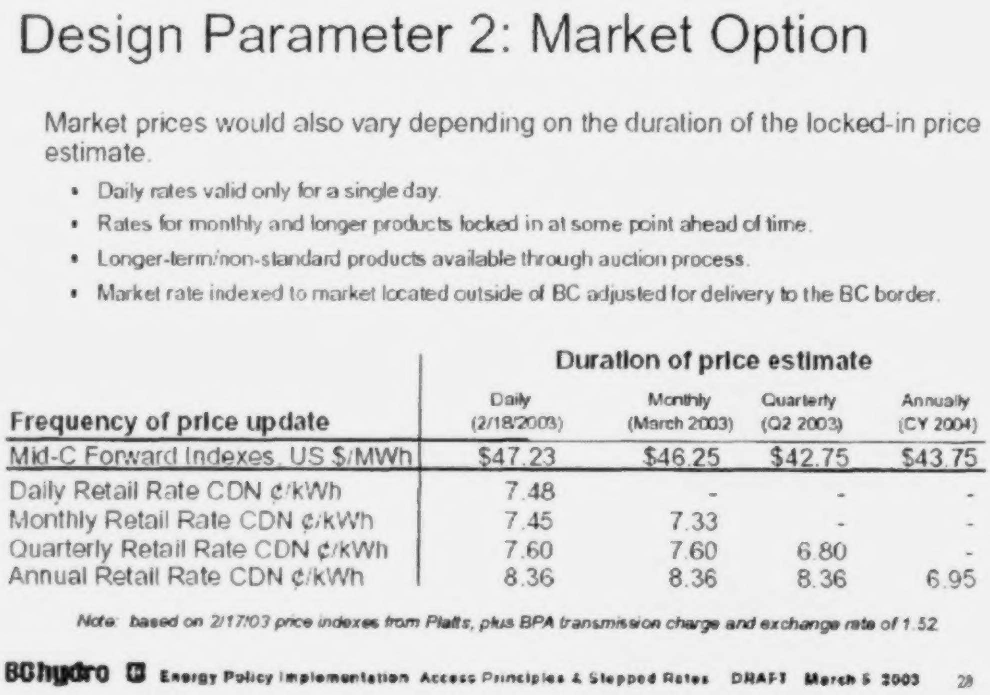
*NYMEX Henry Hub February 2003



Design Parameter 2: Market Option

The market option for calculating the Tier 2 rate is more complicated than the LRIC approach, but provides additional flexibility and a market-based price signal. Market-based rate requires independent estimates of the market value of energy:

- **Price Indexes** for products that are traded in liquid markets. For example, daily and monthly on-peak (6x16) blocks are traded at the Mid-Columbia trading hub, and price indexes are published by a number of sources.
- **Auctions** for forward products that are not widely traded. BC Hydro hires an auctioneer to solicit bids from IPPs and conduct an auction for various blocks per customer election. Because BC Hydro executes a forward contract at the auction price, the auction accomplishes both price discovery and risk management goals.



Design Parameter 2: Market Option

Market prices would also vary depending on the duration of the locked-in price estimate.

- Daily rates valid only for a single day.
- Rates for monthly and longer products locked in at some point ahead of time.
- Longer-term/non-standard products available through auction process.
- Market rate indexed to market located outside of BC adjusted for delivery to the BC border.

	Duration of price estimate			
Frequency of price update	Daily (2/18/2003)	Monthly (March 2003)	Quarterly (Q2 2003)	Annually (CY 2004)
Mid-C Forward Indexes, US $/MWh	$47.23	$46.25	$42.75	$43.75
Daily Retail Rate CDN ¢/kWh	7.48	-	-	-
Monthly Retail Rate CDN ¢/kWh	7.45	7.33	-	-
Quarterly Retail Rate CDN ¢/kWh	7.60	7.60	6.80	-
Annual Retail Rate CDN ¢/kWh	8.36	8.36	8.36	6.95

Note: based on 2/17/03 price indexes from Platts, plus BPA transmission charge and exchange rate of 1.52

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Design Parameter 2: Summary

- LRIC-based rate provides simplicity but no choice:
  - LRIC rate is calculated based on agreed-upon formula.
  - LRIC is unrelated to actual market prices at any given time.
  - Some additional cost because either BC Hydro or third-party supplier takes on price risk.
- Market-based rate provides choice but is complicated to administer:
  - Market prices will vary over time, and will be different for each customer depending on load characteristics and selected update frequency.
  - May require BC Hydro to facilitate price discovery by conducting auctions for products with insufficient liquidity.
  - If customers have choices, need administrative safeguards against potential for arbitrage among available rate designs. This most likely means a sign-up period with commitments of a fixed duration.
- The two approaches probably converge in the long run; long-term deals (e.g., 7-10 years) in the market are probably priced using an LRIC-type method.

Stepped Rate Design Parameters

1: Tier 1 Cutoff Point

2: Design of Tier 2 Rate

3: Customer Direct Access

4: Transmission

Design Parameter 3: Direct Access

Policy Action #14 introduces retail competition for large BC Hydro customers . Direct access means that customer purchases energy from third-party supplier. Stepped rate design can facilitate direct access by some customers while mitigating cost and risk impacts to others.

- Tier 1 rate will probably be too low to allow for significant competition from third-party supplier.
- Under stepped rate with no RTP credit, customers could take direct access for load priced at Tier 2 rate while continuing to take Tier 1 portion from BC Hydro.
- This provides a modest but efficient incentive for third party suppliers to recruit large retail customers.

Design Parameter 3: Direct Access

RTP-type credit for incremental load reduction allows customer to take direct access up to its total energy demand without losing benefit of low 1821 rate, through a shopping credit from BC Hydro.

- The shopping credit would be equal to the Tier 2 rate times the amount of load served directly by a third-party supplier.
- Remaining customers would be held harmless if the Tier 2 rate is equal to BC Hydro s opportunity cost — the value BC Hydro can reap by reselling the power on the wholesale market.
- However, because accurate calculation of opportunity cost is problematic, this poses some risk for remaining customers.
- Direct access customers would benefit:
  - If third-party price is more attractive than BC Hydro s Tier 2 rate.
  - If taking full load to market gets a better price than a smaller increment.
  - If other services such as energy management are bundled with third-party energy supply.

Direct Access example

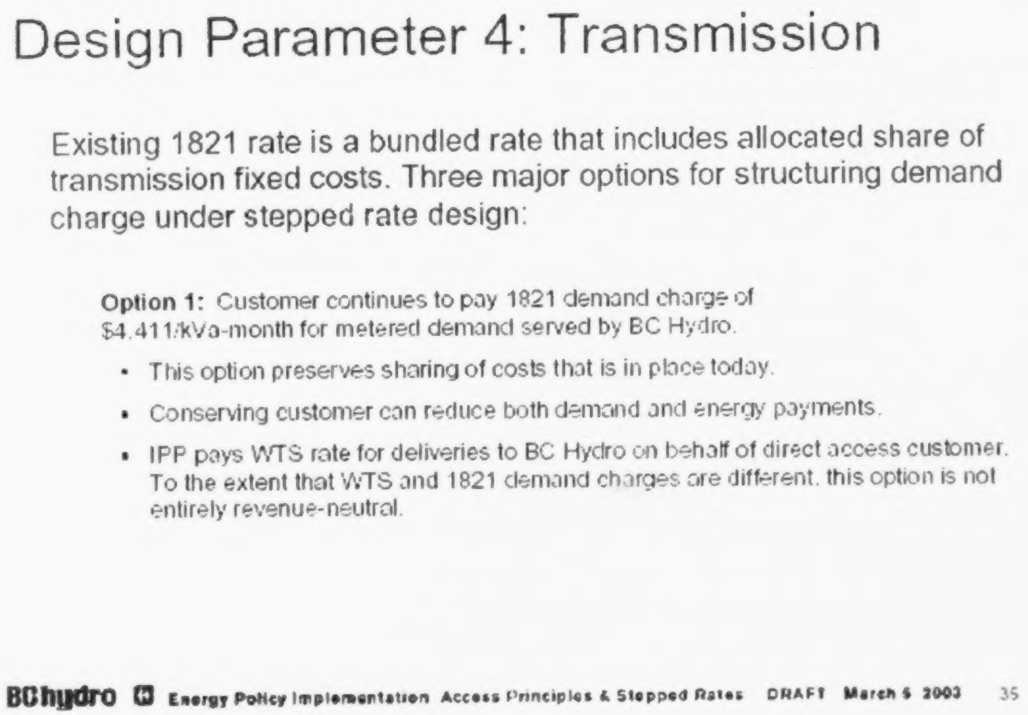
- Bill comparison demonstrates one way to design revenue-neutral retail access.
- Assumes Tier 1 cutoff set at 100% of CBL with RTP-type credit, no Tier 2 bill due.
- Customer takes direct access for entire historical load.
- Customer pays BC Hydro for CBL quantity.
- Customer also pays IPP for energy delivered to BC Hydro.
- Example assumes IPP rate equal to BC Hydro Tier 2 rate. Customer benefits if IPP rate lower.
- Shopping credit equal to BC Hydro Tier 2 rate.
- Shopping credit quantity equal to quantity served by IPP.
- Rate is revenue neutral if Tier 2 rate is equal to BC Hydro s opportunity cost.

Direct Access comparison

	BC Hydro	Direct Access
Monthly customer baseline amount (MWh)	10,000	10,000
Monthly consumption taken from BC Hydro (MWh)	10,000	-
Monthly consumption taken from IPP (MWh)	-	10,000
Total monthly consumption (MWh)	10,000	10,000
BC Hydro Bill		
Tier 1 (lower tier), MWh up to:	10,000	10,000
Tier 1 monthly consumption (MWh)	10,000	10,000
Tier 1 rate (¢/kWh)	2.599	2.599
Tier 1 monthly bill	$259,900	$259,900
Tier 2 (upper tier), MWh greater than:	10,000	10,000
Tier 2 monthly consumption (MWh)	-	-
Tier 2 rate (¢/kWh)	6.200	6.200
Tier 2 monthly bill	$0	$0
Total monthly bill from BC Hydro	$259,900	$259,900
IPP Bill		
IPP monthly consumption (MWh)	-	10,000
IPP rate (¢/kWh)	6.200	6.200
Total monthly bill from IPP	$0	$620,000
Shopping Credit		
Shopping credit quantity	-	10,000
Shopping credit rate	(6.200)	(6.200)
Total shopping credit	$0	($620,000)
Total Monthly Bill		
Monthly bill before shopping credit	$259,900	$879,900
Shopping credit	$0	($620,000)
Monthly bill after shopping credit	$259,900	$259,900
Average rate for all consumption	2.599	2.599

Stepped Rate Design Parameters

1: Tier 1 Cutoff Point
2: Design of Tier 2 Rate
3: Customer Direct Access
4: Transmission

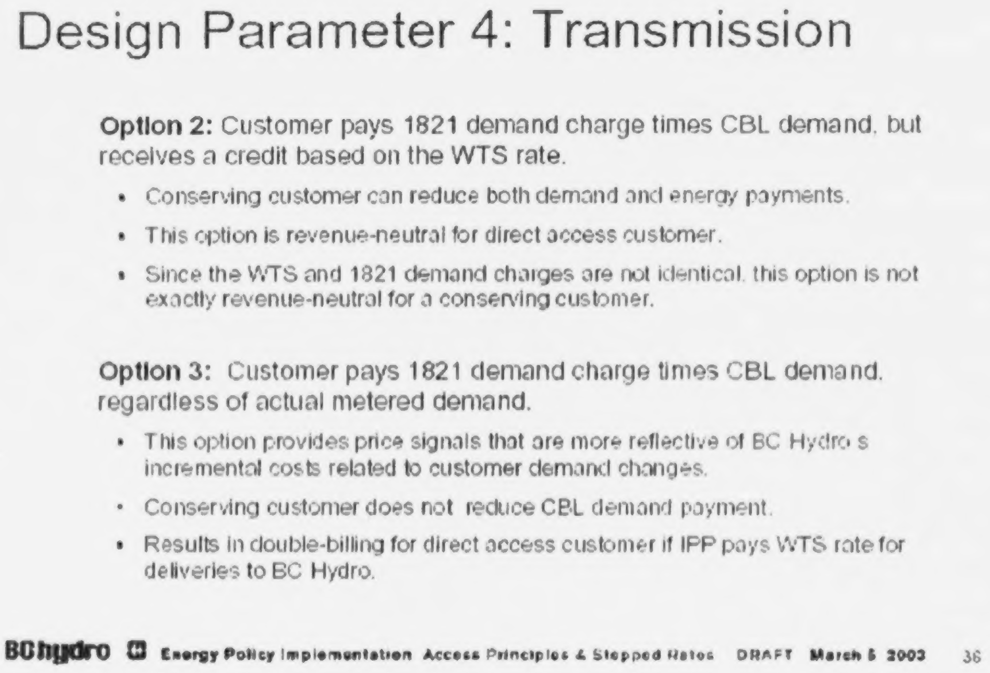


Design Parameter 4: Transmission

Existing 1821 rate is a bundled rate that includes allocated share of transmission fixed costs. Three major options for structuring demand charge under stepped rate design:

Option 1: Customer continues to pay 1821 demand charge of $4.411/kVa-month for metered demand served by BC Hydro.

- This option preserves sharing of costs that is in place today.
- Conserving customer can reduce both demand and energy payments.
- IPP pays WTS rate for deliveries to BC Hydro on behalf of direct access customer. To the extent that WTS and 1821 demand charges are different, this option is not entirely revenue-neutral.



Design Parameter 4: Transmission

Option 2: Customer pays 1821 demand charge times CBL demand, but receives a credit based on the WTS rate.

- Conserving customer can reduce both demand and energy payments.
- This option is revenue-neutral for direct access customer.
- Since the WTS and 1821 demand charges are not identical, this option is not exactly revenue-neutral for a conserving customer.

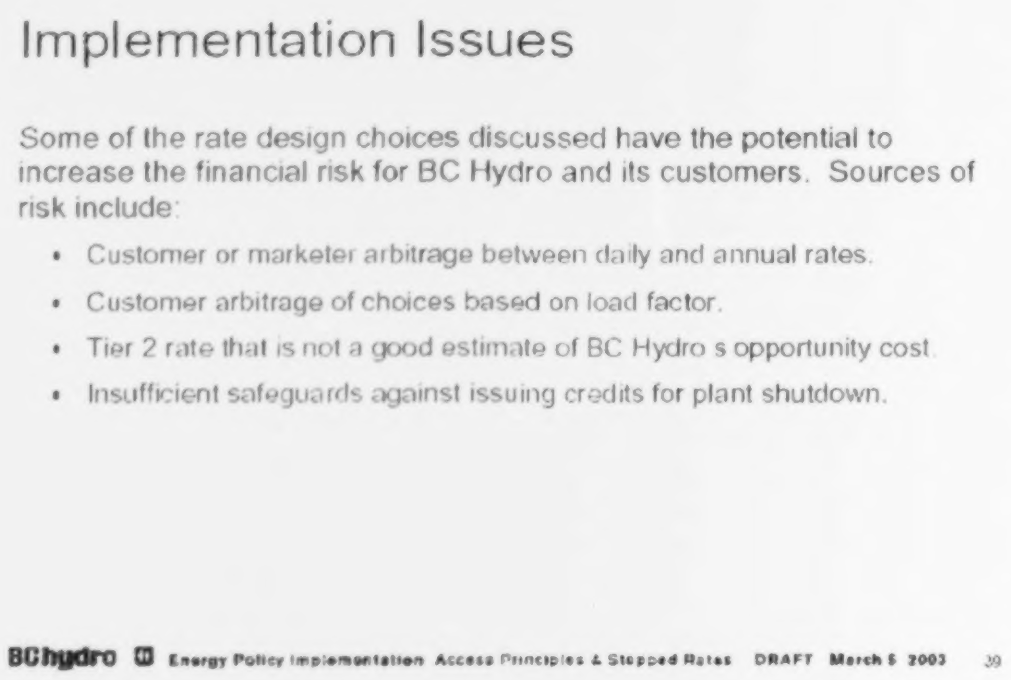
Option 3: Customer pays 1821 demand charge times CBL demand, regardless of actual metered demand.

- This option provides price signals that are more reflective of BC Hydro s incremental costs related to customer demand changes.
- Conserving customer does not reduce CBL demand payment.
- Results in double-billing for direct access customer if IPP pays WTS rate for deliveries to BC Hydro.

Design Parameter 4: Transmission

- For self-generating customers, Options 1 and 2 require resolution of issues related to net vs. gross billing and appropriate charges for occasional transmission use due to on-site plant outages.
- Key policy choice:
  - Options 1 and 2 result in rates that are roughly comparable for all 1821 customers, but affect short-term price signals and are not 100 percent revenue-neutral.
  - Option 3 sends price signals based on incremental generation costs, but double-bills direct access customers and results in different effective rates among customers with similar demand (since demand charges are based on historical demand).

Implementation Issues

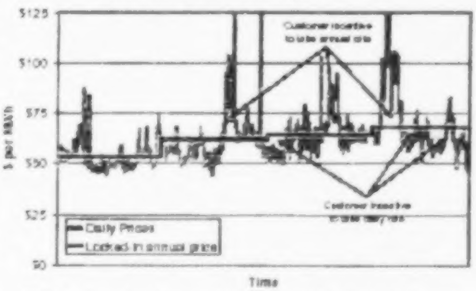


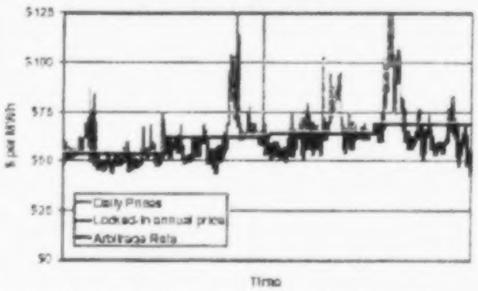
Implementation Issues

Some of the rate design choices discussed have the potential to increase the financial risk for BC Hydro and its customers. Sources of risk include:

- Customer or marketer arbitrage between daily and annual rates.
- Customer arbitrage of choices based on load factor.
- Tier 2 rate that is not a good estimate of BC Hydro s opportunity cost.
- Insufficient safeguards against issuing credits for plant shutdown.

Implementation Issues: Arbitrage of daily vs. annual rates

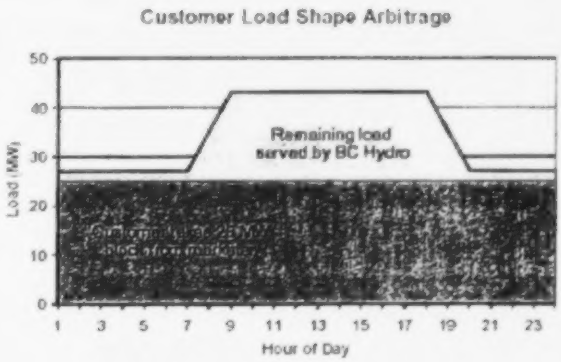

Tier 2 Rate Arbitrage Opportunities


Tier 2 Rate Arbitrage Opportunities

- If given a choice, customers will want daily rates when daily price is lower than annual price, and annual rates when the daily price is higher. Result is lower of rate, which is not revenue-neutral.
- May need administrative mechanisms to prevent cream-skimming and arbitrage. These could include fixed terms of Tier 2 rate choices, accounting mechanisms to ensure that risk management costs are allocated appropriately.
- Balancing energy presents an arbitrage opportunity even with limitations on rate design choices.

Implementation Issues: Arbitrage of load shape

- Marketers will be more interested in serving flat loads.
- If customers are allowed unrestricted choice of market instruments, BC Hydro may be left with undesirable load.
- This increases the per MWh cost of serving 1821 load.
- Tier 2 rate will need to reflect shape of load still served by BC Hydro.



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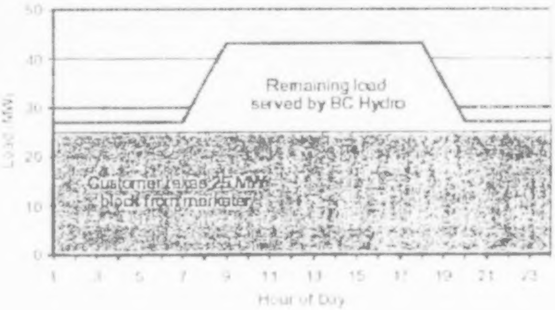
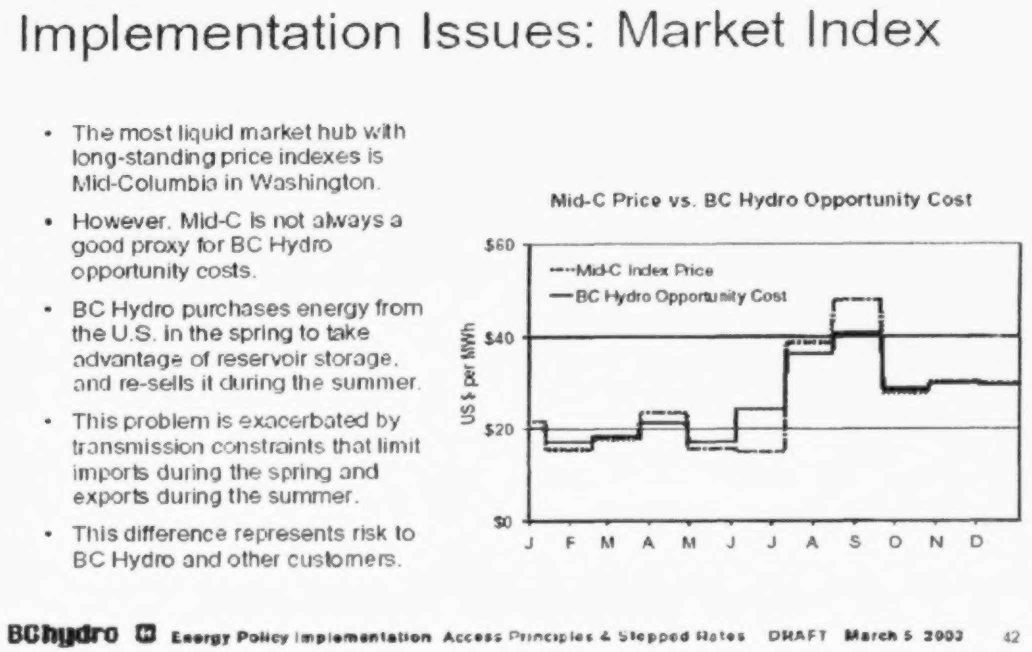


Customer Load Shape Arbitrage



Implementation Issues: Market Index

- The most liquid market hub with long-standing price indexes is Mid-Columbia in Washington.
- However, Mid-C is not always a good proxy for BC Hydro opportunity costs.
- BC Hydro purchases energy from the U.S. in the spring to take advantage of reservoir storage, and re-sells it during the summer.
- This problem is exacerbated by transmission constraints that limit imports during the spring and exports during the summer.
- This difference represents risk to BC Hydro and other customers.

Mid-C Price vs. BC Hydro Opportunity Cost

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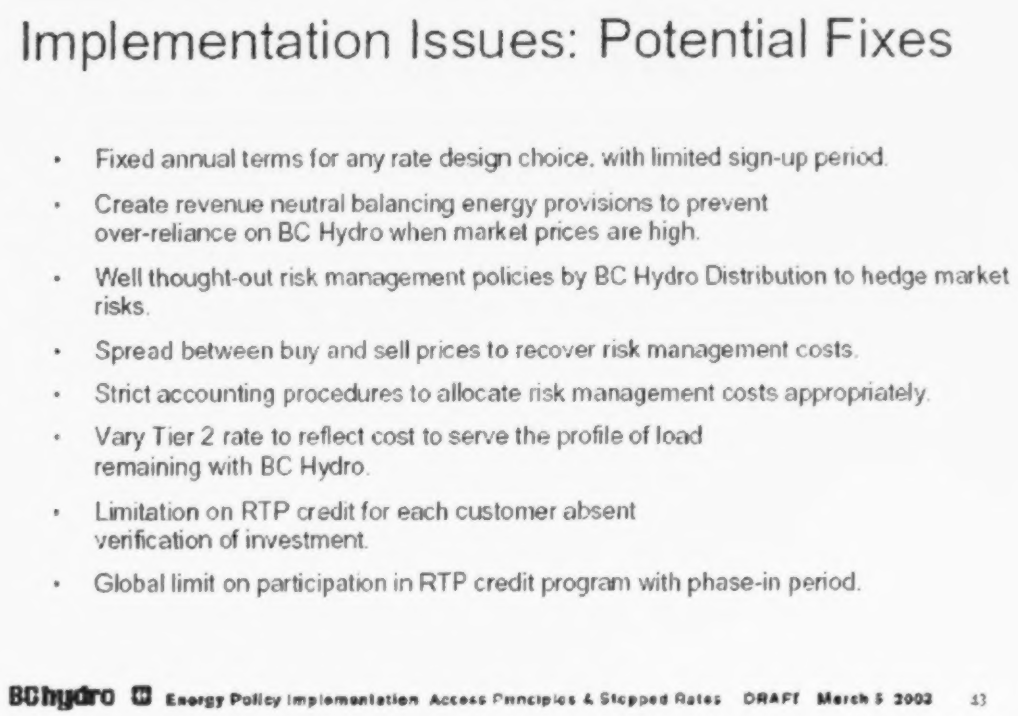
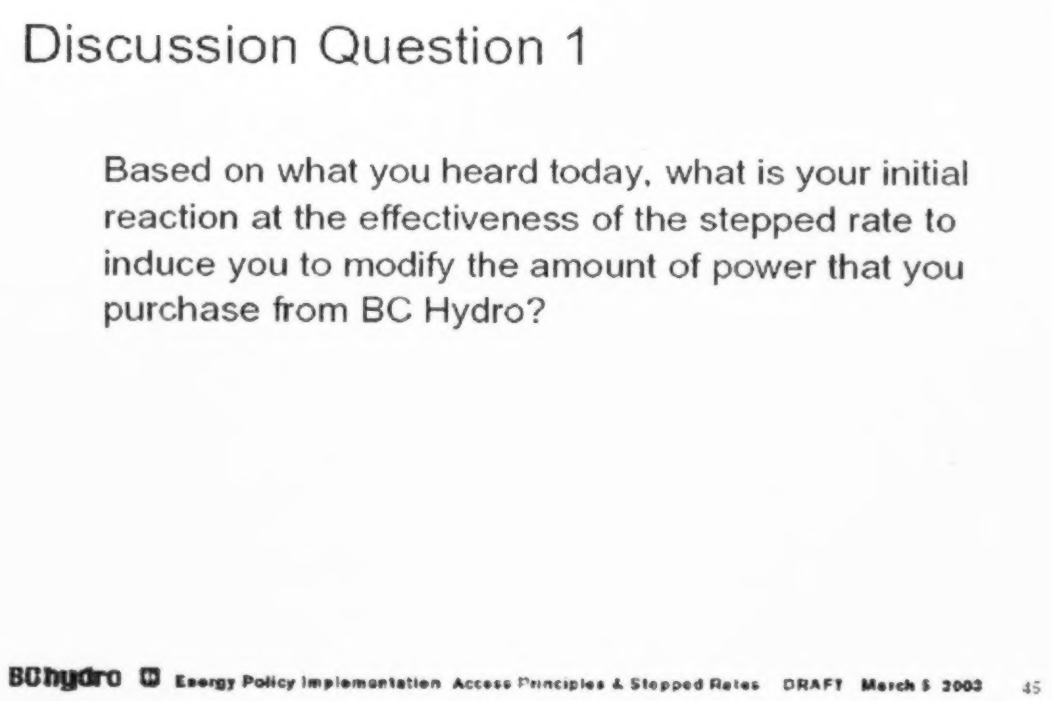


Implementation Issues: Potential Fixes

- Fixed annual terms for any rate design choice, with limited sign-up period.
- Create revenue neutral balancing energy provisions to prevent over-reliance on BC Hydro when market prices are high.
- Well thought-out risk management policies by BC Hydro Distribution to hedge market risks.
- Spread between buy and sell prices to recover risk management costs.
- Strict accounting procedures to allocate risk management costs appropriately.
- Vary Tier 2 rate to reflect cost to serve the profile of load remaining with BC Hydro.
- Limitation on RTP credit for each customer absent verification of investment.
- Global limit on participation in RTP credit program with phase-in period.

Departure Points for Discussion



Discussion Question 1

Based on what you heard today, what is your initial reaction at the effectiveness of the stepped rate to induce you to modify the amount of power that you purchase from BC Hydro?

Discussion Question 2

What are the characteristics of the stepped rate design that would prevent you from modifying your purchases from BC Hydro?

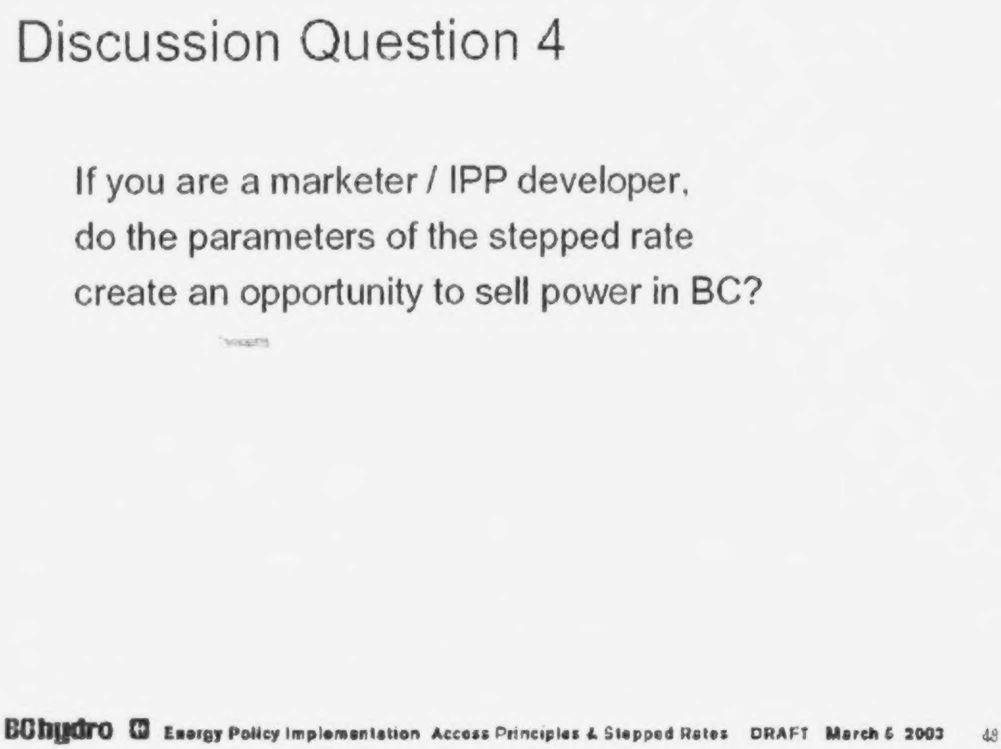
Discussion Question 3

How can the stepped rate be used to:

a) incent investment in conservation OR self generation?

b) contract directly with an IPP for incremental supply?

c) modify your plant operation?



Discussion Question 4

If you are a marketer / IPP developer, do the parameters of the stepped rate create an opportunity to sell power in BC?

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Summary of BC Hydro's March 5 Workshop on Stepped Rates & Access Principles

AT THE MORRIS J WOSK CENTRE FOR DIALOGUE
SIMON FRASER UNIVERSITY

March 14, 2003

A. INTRODUCTION

In accordance with the Province's Energy Plan, BC Hydro will be filing a proposal with the Commission in April 2003 on Stepped Rates and Access Principles for transmission voltage customers. The intention of this new rate structure is to provide the correct pricing signals to encourage customers to undertake efficient Demand Side Management or self-generation initiatives, and to allow for retail access. The new rate will also support new opportunities for independent power producers. In preparation for this filing, BC Hydro held a technical workshop on Stepped Rates and Access Principles on Wednesday, March 5, 2003, to which over 300 transmission-voltage customers, independent power producers and other interested parties were invited.

The goals of the workshop were to: present a number of rate design choices that meet the goals and objectives of the Energy Plan; identify some key implementation issues; and solicit input from customers and other interested parties to assist BC Hydro frame its proposal on Stepped Rates and Access Principles. At the workshop, BC Hydro provided high-level design parameters for Stepped Rates & Access Principles and invited general comments, as well as specific feedback, on the proposed design parameters. BC Hydro is not committed to any of the rate design options presented during the workshop; we are seeking as much feedback as possible over the next few weeks to inform our application to the Commission.

The purpose of this document is to summarize in an objective manner the discussion that occurred throughout the March 5 workshop. As mentioned throughout the workshop, there will be additional opportunities for further feedback and comments prior to our April filing. Another document, titled "Request for Feedback on Stepped Rates and Access Principles" has been appended in order to seek your responses on some specific issues arising from the workshop discussions. Your input will assist in making our April filing on Stepped Rates and Access Principles as robust as possible.

Please forward your comments to Sony Bae, Stakeholder Engagement, Energy Policy Implementation by fax (604) 623-3743 or e-mail (sony.bae@bchydro.com).

We thank you for your input.

B. SUMMARY OF DISCUSSION ITEMS

As the presentation is available on the web site, this summary is limited to discussion items arising from the workshop. Reference is made to the presentation material only as required to frame the issue under discussion.

The following topics were discussed:

1. INTERPRETATION OF THE ENERGY POLICY

BC Hydro provided to workshop participants its thoughts on how the Energy Policy should be interpreted. This included an assumption that shut down of customers facilities in response to the stepped rate would be an undesirable result of this product. It was proposed that this could be addressed by reducing or eliminating the amount of credit received at the higher market price.

A participant questioned this assumption by asking where in the Energy Policy a distinction was made between partial or full shut-down and energy efficiency / self generation. BC Hydro concurred that the view taken by BC Hydro was one of many possible interpretations, and will be subject to further debate.

Concern was also expressed that significant time and money would be spent interpreting aspects of the Energy Policy, and it was asked if any process was in place to resolve these differences (for example, by obtaining specific direction from the government). BC Hydro stated that timing precludes more public debate around Energy Policy interpretation at this time, however this should be covered in subsequent BC Utilities Commission (BCUC) workshops. The government does plan to provide input into the process (to 'book end' the allowable design parameters) in the fall, after they have heard the debate.

2. TIER 1 CUT-OFF POINT

A stepped rate design requires a choice of where to place the cut-off between the tiers. There were two main options presented by BC Hydro for the Tier One cut-off point: (i) a stepped rate, with the first step set at some percentage of the customer historical consumption level (Handout Slide 23; Web Slide 16), and (ii) an Real Time Pricing (RTP)-like mechanism, with the first step set at 100% of the customer's historical consumption level, and increases/ decreases in consumption charged/ credited using a market based price (Handout Slide 25; Web Slide 18).

BC Hydro provided participants with illustrative examples showing that the bill impacts arising from these two rate design options were generally the same (Handout Slide 22; Web Slide 15), however the RTP-like rate design provides significantly more flexibility over the size of energy reductions (through conservation, co-generation or Independent Power Producer supply) that could be credited at the market based price.

For the stepped rate option, cut-off points ranging from 60% upwards were discussed. Concern was expressed by a participant that if the Tier One price is lower than the heritage contract price, it could lead to the implication that industrial customers are getting a subsidy (this is not an issue for the RTP-type design). A participant also stated that if the second tier volume is too small it will significantly limit the incentive of customers to respond to this rate. BC Hydro stated that it would like to hear feedback from customers on their responsiveness to design parameters.

Participants also raised the following alternative rate design options:

- **Stepped Rate Based on Heritage Contract Cost and Market Price:** Under this option the Tier One price would be set equal to the heritage contract price, and the Tier Two price would be set at a market based price. The cut-off between the tiers would be set at a level that ensures no bill impacts where there are no changes in consumption.

A participant provided an illustrative example of this option: if the Tier One price was 2.2 cents/kWh, and the Tier Two price was 5.2 cents/kWh, the cut-off between the two tiers has to be at 86% in order to ensure no bill impacts. A number of participants considered this example a simpler and logical way of approaching this rate design.

A similar rate option was also proposed by a participant which included a Tier One price set at the 1821 energy rate (2.599 cents/kWh), with the Tier Two price based on long-run marginal cost. If the volume of Tier Two energy was considered too small, adjustments to the rate could be made.

BC Hydro stated that tying the stepped rate design to the heritage contract is not a requirement of the Energy Policy, and would result in unnecessary design restrictions. It could significantly limit a customer's ability to benefit from conservation, co-generation and Independent Power Producer (IPP) supply by reducing the amount of energy available at the second tier price (especially if a Tier Two price of around 6.2 cents/kWh or higher is assumed), and would not allow for consideration of the more flexible RTP-type design alternative.

BC Hydro agreed that a discussion of these alternatives and issues would be covered in its April report to the BCUC.

- **Stepped Rate Based on Heritage Contract Cost and Volume:** Under this rate option, the Tier One price would be set equal to the heritage contract price, and the Tier Two price would be set equal to the average cost of BC Hydro's non-heritage generation assets. The Tier One cut-off point would mirror BC Hydro's heritage energy as a percentage of its total portfolio.

  BC Hydro stated that in order to encourage efficient conservation, DSM investment and IPP access, the Tier Two rate should be based on some form of forward market price, rather than historical costs. A participant also stated that a cost based approach would provide less flexibility in rate design.

3. REVENUE NEUTRAL VS. MARGIN NEUTRAL

A concern was raised that a stepped rate design would not be revenue neutral to BC Hydro if it encourages conservation (total revenues from industrial customers would decrease). BC Hydro stated that although the stepped rates would be designed to be revenue neutral from a customer perspective (assuming no change in consumption pattern), it will be designed to be 'margin neutral' to BC Hydro. Assuming the amount credited to customers for conservation equals BC Hydro's opportunity cost, domestic revenues will drop but BC Hydro's margin will remain the same as BC Hydro Distribution can resell the power on the export market.

4. CBL DESIGN

BC Hydro proposes to establish a customer base line (CBL) for each customer based on some estimate of historical consumption (for example, average 2000 to 2002 consumption). This will be used as follows:

- for the stepped rate proposal, the volume of Tier One energy that can be purchased at the low Tier One price is a function of the customer's CBL and the Tier One cut-off percentage.

- for the RTP-type design, the CBL will be used to determine the customers fixed charge (based on the 1821 rate multiplied by the customers CBL), with any decreases / increases in consumption credited / charged at a market based price.

The issue of determining a CBL for new customers was raised. BC Hydro responded that, while there are a number of alternatives, typically a CBL estimate would be developed and trued-up at a later date. A participant also stated that a number of adjustments could be also required, for example to deal with customer response to previous rates such as Price Dispatch Curtailment and the Power Smart Industrial Tariff.

Participants questioned how new projects of existing customers would be treated. Would there be negotiations around increasing the CBL for new projects? BC Hydro agreed that this was an issue. Growth should be at the Tier Two price level, however an artificial distinction should not be created between CBL adjustments for new facilities and substantial modifications to existing facilities. This will be discussed in the report.

5. TIER ONE PRICING

Participants asked how the Tier One price would be set, and what the volatility of this price would be. BC Hydro responded that under the stepped rate proposal, the Tier Two price would be set, and then the Tier One price would be calculated (somewhere below the cost based 1821 rate) so that the customer's total bill does not change if there is no change in consumption. Under the RTP-type proposal, the Tier One price would be set at the 1821 rate, with any decreases in consumption credited back at a market based price (referred to as the "shopping credit").

With regards to volatility, assuming a static regulatory world, the Tier One price is fixed once a customer chooses the Tier Two price option (assuming the shape of energy taken under Tier One does not change). However, if BC Hydro requires an increase in its revenue requirement, the Tier One price (or its volume) can be changed by the BCUC to ensure that all customers pay their fair share of any increase.

6. TIER TWO PRICING/SHOPPING CREDIT

BC Hydro stated that the Tier Two price (also called the 'shopping credit' under the RTP option) could be based on BC Hydro's long-run incremental costs (LRIC), or indexed to wholesale market prices (Handout Slide 30; Web Slide 22).

6.1 ADMINISTRATIVE LRIC ESTIMATE

BC Hydro proposed that the Tier Two price / shopping credit reflect market prices, and these could vary depending on the term of the commitment chosen by the customer. For example, a 5 to 10 year contract could be priced using an administrative estimate of BC Hydro's LRIC (such as the fully allocated cost of combined-cycle gas turbine), or through a BC auction mechanism.

For shorter periods, the Tier Two could be linked to an index (such as Mid-C) or could also be developed through a BC auction mechanism.

BC Hydro estimated its LRIC as being between 6.2 cents/kWh and 7.9 cents/kWh - based on the fully allocated cost of Combined Cycle Gas Turbine (CCGT) and assuming a long-run fuel cost of US $4.14 (Handout Slide 33; Web Slide 25). A number of issues were raised around this method of determining the LRIC:

- **Use of 'Real' Contract Prices:** It was proposed that the actual prices of new energy contracts acquired by BC Hydro Distribution be used, rather than hypothetical estimates.

BC Hydro does have a slight surplus of generating capacity, but is acquiring new resources where economic, to encourage private sector development and to promote green supply.

As a result, it has entered into 22 contracts for delivery in 2006 at an average price of 5.2 cents/kWh, however this should not be automatically interpreted as providing a price signal. This will be addressed in the report.

- **Use of Power Smart Prices:** It was proposed that the cost of Power Smart acquired energy (2.5 cents/kWh) could also be used to determine the LRIC. BC Hydro responded that the 2.5 cents/kWh only represents the contribution Power Smart makes to encourage conservation or co-generation investment. If the cost of lost revenue is added, the total cost to BC Hydro rises to around 6 cents/kWh.

- **Use of Coal Instead of CCGT:** The use of a coal plant, rather than a CCGT, to determine the LRIC was raised as an alternative. This was linked to concerns about the gas price volatility if a CCGT was used to estimate LRICs.

  BC Hydro stated that, based on estimates from the American Midwest, the costs of a coal plant compared to a CCGT were similar (a coal plant will have higher construction costs but lower operating costs compared to a CCGT). The use of forward gas prices (US $4.14) in the LRIC calculation for a CCGT addresses the issue of gas price volatility.

  For short-term prices, it would be better to use a market index rather than an administrative estimate to take account of gas price volatility.

- **Green Premium:** A participant stated that conservation is green, and so should be worth more than the LRIC estimate based on the CCGT cost. It was also proposed that consideration should be given to a higher price paid for 'Negawatts' resulting from conservation.

  BC Hydro agreed that inclusion of a green premium in determining LRIC should be considered, and that LRIC could also be based on the cost of a super efficient CCGT that does not yet exist.

- **Environmental Costs:** A question was raised as to whether the costs arising from implementation of the Kyoto Protocol and other environmental initiatives had been considered in the CCGT calculation. BC Hydro stated that anticipated environmental costs become a legitimate part of the cost of new supply and should be factored in, or this risk could be addressed through the use of a risk premium.

- **Set Based on Market Impact:** A participant stated that the Tier Two price/shopping credit must be high enough to elicit a response from customers. While the participant agreed that cost is important, the participant considered that setting the Tier Two price/shopping credit as high as reasonably possible would result in the maximum incentive to conserve.

  However, another participant stated that the impact on growing customers should also be considered – if the Tier Two price is set too high it will discourage relocation of production from other Provinces to BC. Another participant also said that the impact of reducing production compared to incenting conservation should be considered.

  A participant noted that there are conflicting needs of IPPs, who the participant considered would want a high Tier Two price/shopping credit, and other customers who would prefer a predictable Tier Two price/shopping credit over a long period of time. BC Hydro stated that this is one of the areas that they are looking for support/insight into.

  A participant also stated that BC Hydro should focus on a simple and effective program that supports long-term (20 year) IPP, co-generation and conservation objectives, rather than shorter-term retail competition.

- **Volatility:** Concern was raised that if the LRIC estimates were too volatile (it has already changed from $55 last fall to $65 now), the rate will be unworkable. The risks of having a LRIC price that turns out to be higher or lower than the actual market price was also raised.

  BC Hydro stated that if we offer customers a long-term price, the BC Hydro Integrated Electricity Plan could include risk management products to address this risk.

6.2 AUCTION PROCESS

BC Hydro put forward the option of an auction process to determine the market price for forward products that are not widely traded (for example, that are not monthly one-peak (6 x 16) blocks with a 100% load factor). BC Hydro could use an auction process to solicit bids from IPPs for various blocks as required by the customer. As well as providing price discovery, this would enable BC Hydro to hedge the Tier Two price/shopping credit offered to the customer.

There was significant debate over the benefits of an auction process compared to a long-term Tier Two price offering by BC Hydro, followed by bilateral negotiations between IPPs and customers. BC Hydro responded that an auction process would benefit customers by determining the lowest price, and also reducing the risk to BC Hydro. However, if other policy goals are considered more important (such as rate simplicity), then a different option could be adopted.

6.3 MARKET INDEX

The shorter-term market price could be based on a market index, such as Mid-C (Handout Slide 35; Web Slide 27). A participant stated that a long-term price would be preferable for measuring the benefits of a long-term project, although a shorter-term price may be better for customers who can respond to these price signals.

Concern was raised as to whether Powerex can impact the short-term or long-term market price in BC. BC Hydro responded that the long-term price is based on LRIC, and Powerex has no impact on that. The Mid-C price is influenced by supply and demand factors throughout the West Coast, Mexico, California, Oregon, Washington, Utah and Alberta.

6.4 TIME OF USE / SPOT PRICING OPTIONS

Participants raised the option of a time-of-use Tier Two price, and shorter-term prices that would allow customers to take advantage of price volatility in the wholesale market. BC Hydro agreed that these are possible options, although the prices may not be transparent as there is no clear BC market price. Index prices elsewhere may not be appropriate in BC for all hours as a result of the impact of storage and transmission constraints.

Until the stepped/RTP-type rate is in place, other rate designs (such as the Power Smart Industrial rate) can continue to be used to provide customers with short-term market price opportunities.

6.5 THIRD TIER PRICING (BUY / SELL SPREAD)

A participant raised the possibility of a stepped rate design with a Third Tier that kicks in at 100% of the customers CBL. The Second Tier price could be below market, with the Third Tier price above market. It was considered that this design could address the problem of protecting BC Hydro from uneconomic growth.

BC Hydro responded that this is similar to the concept of a buy-sell spread on the RTP-like rate design. A lower price (shopping credit) is paid to customers for conservation, while a higher price is charged to customers for additional consumption over their CBL. Preserving such a buy/sell spread will help ensure that there are no impacts on non-participating customers. However, for symmetry, an accurate market price should make BC Hydro indifferent to crediting customers for decreases in consumption & charging customers for increases in consumption.

7. TRANSMISSION ADDER

BC Hydro stated that the Tier Two Price/Shopping Credit could include or exclude a transmission adder (Handout Slides 46 & 47; Web Slides 35 & 36). If included, it could be based on incremental transmission costs, embedded transmission costs, the 1821 demand charge or the wholesale transmission services rate. If it is excluded, customers selecting IPP access could receive a credit for wholesale transmission costs paid that they have already paid for as part of their CBL.

8. TRANSITION ISSUES

A concern was raised that energy efficiency improvements will be put on hold until the new rate comes into effect. BC Hydro stated that they were also very concerned about this, and hope to work with customers and the BCUC to ensure energy efficiency and self-generation programs can be put in place in a timely manner through the transition period. BC Hydro welcomes any suggestions to avoid unnecessary delay due to uncertainty during the transition period. One proposal raised to address this concern was for early establishment of customer CBLs. A number of participants thought that this would be a good topic to discuss at subsequent workshops.

Post meeting note: BC Hydro understands that the extended regulatory process in Stepped Rates may create uncertainty for RS1821 customers on the economic benefits of investments under BC Hydro's Customer Based Generation & PowerSmart programs (relative to Stepped Rates). BC Hydro is developing a policy for RS1821 customers (that holds other rate class of customers harmless) to address the uncertainty during this transition period so economic investments are not deferred.

9. SIMPLE VS. ACCURATE RATE DESIGN OPTIONS

A participant proposed that it may be better to come up with ideas that are simple and address the main goals of the rate design (simplicity, transparency and certainty around the price), even if simple designs result in a few perverse incentives. BC Hydro responded that there is a trade-off between a complicated design and complicated access rules, and we can strive for a happy medium.

However, another participant stated that we should ensure that benefits obtained for the Industrial customer class are not obtained at the expense of other customer classes. There has to be a mechanism to ensure (i) if non-participants are subject to risks, the risks are not just on the down side, and (ii) access principles are flexible enough to meet the goals while ensuring the benefits gained are not at the expense of other customers.

Net metering was proposed as one option to simplify the process. The customer would automatically receive the Tier Two price / shopping credit, and the transmission component could be dealt with separately. BC Hydro agreed that this is one mechanism that could be used to implement the rate.

10. IPP ACCESS

BC Hydro stated that the stepped rate / RTP-like rate would provide customers with the ability to purchase their market priced portion of energy from an IPP instead of BC Hydro (Handout Slide 47; Web Slide 36). A number of issues were raised around this.

10.1 BILATERAL ACCESS MODEL ALTERNATIVE

It was proposed that BC Hydro should also consider a bilateral model similar to that of natural gas (wheeling charge plus a competitive energy charge) as this would be simpler. BC Hydro responded that this would not be possible without a full restructuring of 1821 (which would result in bill impacts) and changes to the wholesale transmission tariff (which is designed for wholesale rather than retail transactions). Without these changes, the stepped rate/RTP-type rate proposal is the simplest way to implement the Energy Plan objectives.

10.2 TRANSMISSION CHARGES FOR IPP ACCESS

A participant stated that for IPP access, customers should be able to purchase energy from an IPP using a transmission rate that is not onerous. BC Hydro stated that the simplest way to address this would be through the use of the direct access rate, without modification to the wholesale transmission service process. Training will be made available to Industrial customers.

BC Hydro also stated that a customer taking IPP supply would not have to pay twice for transmission service. If the Tier Two price / shopping credit does not include an adder for transmission, then the IPP customer will receive a bill credit for payment of wholesale transmission charges to the extent that these services have already been paid as part of their CBL.

10.3 IMPACT OF TRANSMISSION SERVICES COMPANY FORMATION

An issue was raised as to the impact the formation of a Transmission Services Company will have on BC Hydro's position. BC Hydro responded that the Transmission Services Company will not own BC Hydro assets, and Wholesale Transmission Service (WTS) probably will not be redesigned until 2004. At that point, BC Hydro will look at the impacts on any rate designs.

A participant stated that they suspect the existing transmission rates are not too far off the mark.

10.4 IMPACT OF IPP LOCATION

A question was raised about the impact of IPP location on the Tier Two price / shopping credit. BC Hydro responded that IPP location could only impact the Tier Two price if the Tier Two price includes transmission locational credits or costs. Current wholesale contracts entered into by BC Hydro do provide adjustments for certain projects based on transmission location specific costs.

The IPP itself may be impacted by location through its transmission connection charges.

10.5 CHARGES FOR LOSSES / ENERGY IMBALANCE

A participant asked if customers taking IPP access would also be charged for the 6% losses under the wholesale transmission service. BC Hydro responded that the customer would have to purchase losses and energy imbalance service if they are taking supply from the IPP. However, the Tier Two price / shopping credit would reflect the cost of purchasing these services from BC Hydro and so the customer would not be paying for these services twice.

To ensure no negative impacts on non-participating customers, the energy imbalance charge could be based on the actual cost (market price) to BC Hydro of truing up the IPP purchase to meet the customer's needs.

10.6 LEVEL PLAYING FIELD FOR IPPS

Concern was raised that a high spread between a stepped rate Tier One price and Tier Two price will provide customers with old, energy intensive plants with a strong incentive to reduce production, obtain funding for Power Smart programs or install co-generation. This would reduce opportunities available to IPPs. Preference was also expressed for the RTP-type rate over the stepped rate.

Inclusion of a transmission adder onto the Tier two / shopping credit price will increase the credit received by the customer for conservation, energy efficiency and co-generation beyond that available to IPPs. This is one of the issues that will be addressed in the report.

Several participants stated that one of the major issues with respect to IPPs is reliability and the issue of storage. Several participants considered that BC Hydro has a huge advantage here in meeting customer needs. BC Hydro stated that standby and energy imbalance will be addressed in the report.

10.7 CERTIFICATION OF MARKETERS

A participant asked if the IPP markets would be open to certified marketers, and if so who are the marketers and who would certify them. BC Hydro responded that there was an assumption that the marketers would include Powerex, and that a certification process would be in place. BC Hydro also stated that this is a sophisticated business, and customers may want to align themselves with consortiums (such as TransAlta) who have the expertise to open this market for them.

10.8 IPP ACCESS TO THE GRID

A concern was raised about IPP access to the Transmission grid for exports and to serve domestic customers.

For exports, BC Hydro responded that an open access tariff is in place, however if you reserve long or reserve big you can get priority over other reservations. Also, reservations are on a first come first served basis. BC Hydro agreed that IPP access to the transmission system for export is an issue.

For access within BC, BC Hydro stated that this should not be a problem. BC Hydro did note that there are occasional constraints from the Interior to the Lower Mainland, and there is a potential issue through to Vancouver Island.

BC Hydro stated a customer could request incremental additions to the transmission system under the wholesale transmission service tariff.

C. SUMMARY OF PARTICIPANT RESPONSE TO DISCUSSION QUESTIONS

Workshop participants were provided with four departure points for discussion during the facilitated afternoon session. Along with the departure points for discussion, a high-level summary of some of the responses is provided below.

1. Based on what you heard today, what is your initial reaction at the effectiveness of stepped rates to induce you to modify the amount of power that you purchase from BC Hydro?

There was general agreement from participants that stepped rates are an effective way to reduce consumption, however concerns were raised that the rate designs discussed were unnecessarily complex and could lead to a deferment of conservation investments in the interim period.

2. What are the characteristics of the stepped rate design that would prevent you from modifying your purchases from BC Hydro?

Participants were concerned about the complexity of the stepped rate product, price volatility and transparency, and restrictions over the amount of conserved energy that would be credited at a market based price.

3. How can the stepped rate be used to incent the following:

a) Invest in conservation or self generation?

Participants stated that conservation and self-generation would be enhanced by a high tier two rate, that provides a credit for transmission and reflects the environmental benefits of conservation. Some participants preferred time-of-use pricing options, firm long-term prices and access to storage, standby and energy imbalance rates.

b) Contract directly with an IPP for incremental supply?

Participants stated that to contract with an IPP they required price certainty, a sufficiently high Tier Two price, simple and reasonable transmission access, access to storage, standby and energy imbalance and sufficient percentage of customer CBL energy priced at market price.

c) Modify your plant operation?

Participants stated that to modify their plant operations they required firm long-term prices with a sufficiently high Tier Two price. Time-of-use and spot pricing options would also be of benefit.

4. If you are a marketer / IPP developer, do the parameters of the stepped rate create an opportunity to sell power in BC?

An IPP participant stated that fair transmission access and access to storage and back-up would create more opportunities for IPPs. The Tier Two price should not be so high that customers focus on shutting down operations / DSM instead of looking at alternative sources of supply, and should create a level playing field between IPP and co-generation. There should also be sufficient portion of customer's CBL priced at market priced energy to provide customers with an incentive to obtain alternative IPP supply.

D. CLOSING COMMENTS

This document of summary notes meets our commitment to inform, communicate and document the discussion during the March 5 Workshop on Stepped Rates and Access Principles. In an effort to obtain further feedback, we have highlighted five issues arising from the March 5 workshop discussion. They appear at the end of this document. Your input will assist in making our April filing as robust as possible.

If you were unable to attend the workshop, the presentation material and the departure points for discussion are both available at the BC Hydro Energy Policy Implementation web site (www.bchydro.com/energyplan).

Please forward your comments on this document or any other issues pertaining to Stepped Rates and Access Principles to:

Sony Bae
Stakeholder Engagement
Energy Policy Implementation
fax: (604) 623-3743
e-mail: sony.bae@bchydro.com

BChydro

Highlights from March 5 Workshop Discussion for Customer and Interested Party Feedback

In order to facilitate dialogue that would further shape the April Filing on Stepped Rates and Access Principles, BC Hydro is seeking specific feedback from customers on the following rate design issues:

1. Stepped Rate vs. RTP-like Design

A stepped rate design requires a choice of where to place the cut-off between the tiers. There are two main options for the Tier One cut-off point:

- Stepped Rate Design: this would set the Tier One volume at some percentage of the customer historical consumption level (60% or higher). An alternative proposal would be to have the Tier One volume linked to the heritage contract or the 1821 energy charge – this would restrict the size of Tier One to around 85% or higher.

A low Tier One volume could result in an unacceptably low Tier One price, while a high Tier One volume would restrict the customers ability to receive market based credits for conservation, self-generation, shut-down and IPP supply.

- RTP-like mechanism: this sets the Tier One volume at 100% of the customer's historical consumption level, and increases / decreases in consumption are charged / credited using a market based price.

This allows customers to continue to benefit from BC Hydro's low cost generation for existing consumption levels, and because the Tier One price is based on the 1821 tariff it does not raise an issue of energy being supplied at below Heritage Contract cost. However, unlike the stepped rate design, it potentially allows customers the full benefit of market based credits for conservation, self-generation, shut-down and IPP supply.

BC Hydro would like to hear feedback from customers on their responsiveness to all the proposed stepped rates and RTP-type design parameters, as well as opinions and suggestions on what would constitute an "unacceptably low" price for the stepped rate Tier One block.

2. CBL Design

BC Hydro proposes to establish a customer base line ("CBL") for each customer based on some estimate of historical consumption (for example, average 2000 to 2002 consumption). This will be used to determine the quantity of energy a customer can purchase at embedded cost based prices.

BC Hydro proposes that growth should be at the Tier Two price, and to achieve this the CBL should not be adjusted upwards once set. However, BC Hydro would like to avoid creating an artificial distinction between new facilities (where a new CBL will be determined) and substantial modifications to existing facilities. A fixed CBL could also allow a customer to continue to receive market based credits for facilities that have been shut down.

BC Hydro is soliciting feedback on how to treat CBL's on a balance basis between new customers, existing customer growth and customers who have curtailed operations.

3. Determining the Market Energy Price

The market energy price will be used to set the stepped rate Tier Two price, or to determine the credit / charge for variances from historic consumption patterns for the RTP-type rate.

BC Hydro is looking for specific feedback on the following issues:

- ***Are customers looking for shorter term price alternatives (for example, hourly, yearly) in addition to a long-run market based price?***
- ***What would be the appropriate mechanism to determine the long-run and short-run market price?***
- ***For conservation, shut-down, self-generation and IPP access customers, what mechanism should be put in place to ensure that the credit paid to the customer reflects the firmness, shape and term of the power that it is being replaced with?***
- ***Should the market price include a premium for green energy supply?***
- ***Should there be a difference between the buy / sell price? For the stepped rate option, this would be equivalent to a Tier Three price that takes effect at 100% of the customers CBL.***

4. Transmission Adder

The Tier Two Price could include or exclude a transmission adder based on sunk transmission costs. If included, it will allow conservation, shut-down and self-generation customers to receive a reduction in their transmission charge even though BC Hydro will see no or minimal reduction in transmission costs. It will also result in an increased costs for growing customers. The transmission adder could be set based on embedded transmission costs, the 1821 demand charge or the wholesale point to point demand charge.

If excluded (or if it is based on low incremental transmission costs), it could result in customers obtaining supply from an IPP being asked to pay twice for transmission access (once through their CBL and again through the wholesale point to point charges). This could be addressed by providing these customers with a credit for wholesale transmission charges they have already in effect paid for under their CBL.

BC Hydro welcomes feedback on the appropriate treatment of sunk transmission costs.

5. Level Playing Field for IPPs

BC Hydro is proposing that IPPs seeking to supply retail customers obtain transmission access through the wholesale transmission tariff. The customer would be responsible for purchasing real power losses (either from BC Hydro or an alternative supplier), and would be charged for energy imbalance service based on the actual cost (market price) of BC Hydro providing this service.

BC Hydro welcomes input on the appropriate mechanism to arrange and pay for transmission access for customers who select an IPP supplier.

BChydro INFORMATION SESSION & WORKSHOP ON

Stepped Rates & Access Principles

WEDNESDAY, MARCH 5, 2003

MORRIS J WOSK CENTRE FOR DIALOGUE, SIMON FRASER UNIVERSITY
580 WEST HASTINGS STREET, VANCOUVER BC

DEPARTURE POINTS FOR DISCUSSION DURING FACILITATED AFTERNOON SESSION
1PM ASIA PACIFIC HALL, WOSK CENTRE FOR DIALOGUE

1. Based on what you heard today, what is your initial reaction at the effectiveness of the stepped rate to induce you to modify the amount of power that you purchase from BC Hydro?

2. What are the characteristics of the stepped rate design that would prevent you from modifying your purchases from BC Hydro?

3. How can the stepped rate be used to incent the following:

a) Invest in conservation or self generation?

b) Contract directly with an IPP for incremental supply?

TIER 2 PRICING SHOULD ENCOURAGE IPP PRODUCTION & HENCE SUPPORT THE NEW ★ ENERGY POLICY, SUGGEST PRICE = 7.0 CENTS /kWh. SHOULD USE THIS PRICE AS AN OFFER BY BCH TO ALL COMERS.

★ INCLUDES ALL GREEN CREDITS

c) Modify your plant operation?

4. If you are a marketer/IPP developer, do the parameters of the stepped rate create an opportunity to sell power in BC?

I would like my feedback individually identified and appended to BC Hydro's proposal on Stepped Rates and Access Principles, which will be submitted to the BCUC on April 11, 2003.

NAME DAVID ANDREWS
TITLE ~~[illegible]~~ CHAIR.
COMPANY CLOUDWORKS ENERGY INC
PHONE (604) 633-9885
FAX (604) 633-9991
EMAIL D.ANDREWS@CLOUDWORKSENERGY.COM
SIGNATURE

This feedback may be faxed back to BC Hydro c/o Sony Bae, Task Leader for External Stakeholder Engagement, Energy Policy Implementation. Fax (604) 623-3743 Phone (604) 623-3626. For more information visit www.bchydro.com/energyplan

**Joint Industry Electricity
Steering Committee**

VIA E-MAIL

March11, 2003

Ms Sony Bae
Task Leader for External Stakeholder Engagement
Energy Policy Implementation
BC Hydro
Vancouver BC

Dear Ms Bae,

The members of the Joint Industry Electricity Steering Committee (JIESC) wish to thank you and BC Hydro for the opportunity to participate in your workshop on March 5, 2003. Both parties will benefit if we can help BC Hydro develop a proposal to the BC Utilities Commission (BCUC) that has the support of your industrial customers. The fewer issues we have before the BCUC, the less time and resources will be required to reach resolution.

We have the following comments on the information presented at the workshop:

Power Availability and Price

Policy Action 1 mandates the creation of a Heritage Contract that will lock in the benefits of low cost hydropower for BC Hydro customers.

Policy Action 5 states that "The BC Utilities Commission will once again regulate BC Hydro rates." In explaining this policy further, the energy policy document, at page 27, elaborates as follows "Rates will again be regulated to cover the projected costs of electricity to consumers." Therefore, it is the expressed intent that customers pay cost based rates.

Policy Action 21 in the energy policy is as follows: "New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency."

We believe the only way to develop a stepped rate program that is consistent with these stated policies is to base both Tier 1 and Tier 2 rates on the applicable cost of service. Tier 1 rates would be based on the cost of Heritage power, and Tier 2 rates on the projected cost of BC Hydro's various other sources of supply, including IPP's and market purchases. This structure will result in a higher cost based rate for Tier 2 power and create the desired cost based market driven incentive for customer generation, various other options and demand side management contemplated in the Energy Policy. Over time, as demand growth shifts the ratio of Tier 1 to Tier 2 power available to industrial consumers, and Tier 2 power costs escalate, this incentive will increase. Initially, the average of the Tier 1 and Tier 2 rates should approximate the current Tariff 1821 rate, which is based on the average cost of all BC Hydro supply.

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This cost based system will provide an open and transparent process for future rate adjustments. In addition, periodic reallocations of Heritage power will be required to accommodate load growth.

Table 1 – Allocation of Heritage Power out lines our understanding of how the Heritage Power will be allocated.

Table 1 – Allocation of Heritage Power

TOTAL HERITAGE VOLUME		
Residential Allocation	**Commercial Allocation**	**Industrial Allocation**
		Customer 'A'
		Customer 'B'
		Customer 'C'
		-
		-
		-

Time and resources are required to be spent defining the volume, allocation and cost of Heritage power, and the process to manage reallocation going forward. In addition, we feel that the Tier 2 power must be better defined to allow for proper forward planning for capacity and price.

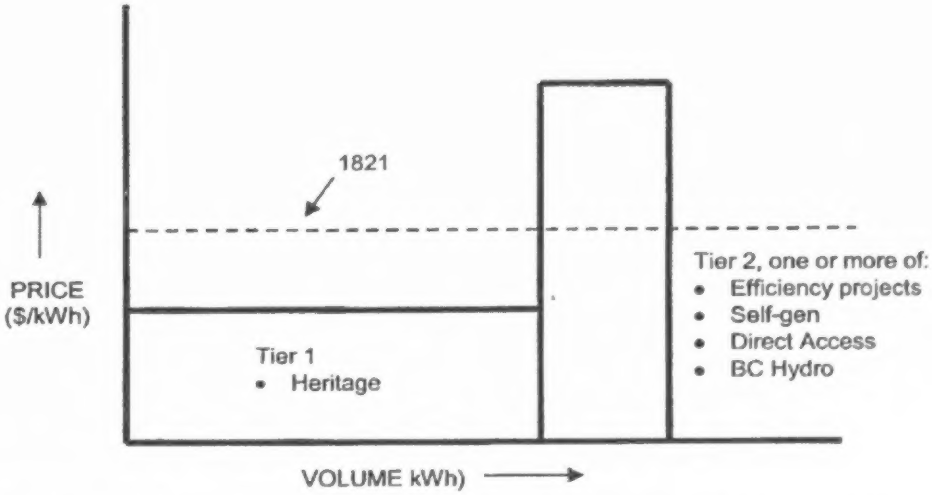
Second Tier Rate Determination

The presentation by BC Hydro repeatedly suggested a two tier rate where the second tier applicable to the last amount of power purchased in a billing period would be representative of "market." However, this approach would not accommodate the Policy objectives to provide cost based rates regulated by the BCUC, nor allow industrial customers to benefit from BC Hydro's trading activities. In addition, we would point out that there is no actual "market" for electric power in BC, so to implement a "market " based pricing system would expose BC customers to US markets. This is not consistent with the Policy objective of maintaining the "BC Advantage" in electricity prices. As suggested above, the Tier 2 rates should be set by BCUC based on the cost of BC Hydro to acquire its portfolio of non-heritage power supply.

The Energy Policy promises that the new stepped rate will result in the same bill to the customer as the current one-step rate, if consumption continues at historic levels. Given that the existing 1821 rate is cost based, we believe the results of proceeding as outlined above will result in total electric power costs closely comparable to the current 1821 tariff where the customer continues to consume power at historic levels.

An outline of this approach to rate design is shown in Table 2 – An industrial Customer's Power Supply.

Table 2 – An Industrial Customer's Electricity Supply



The Tier 2 rate is the cost of BC Hydro acquiring its portfolio of non-heritage supply.

Customer Base Line (CBL)

The JIESC endorses the use of a CBL based on historical usage, adjusted for the appropriate anomalies. This CBL would be used to determine the base consumption level under the stepped rate pricing structure, and would be priced by the BCUC based on the cost of Heritage power. The objective should be that the CBL reflect normal ongoing operations of any individual industrial customer. The allocation process would allow existing industrial customers to purchase a specified percentage of their CBL from BC Hydro at the Heritage Rate.

The concept of a CBL for existing customers poses some problems for new and expanding businesses. Electric power will have to be available to new and expanding businesses under similar terms as existing businesses. This creates some difficulty in the Heritage allocation, because we believe that all Heritage power should be allocated to keep customer costs as low as possible. The issue then is how to supply a new or expanding industrial customer with fair access to Heritage rated power. This issue also needs discussion as the design and implementation of the Heritage power contract is considered.

Demand Charge – Transmission Tariff

There were three options presented for assessing the demand charge. We would suggest that practical considerations will probably dictate maintenance of the existing demand charge as is until such time as the BC Transmission Operator files for a tariff. This is nearly equivalent to proceeding with Option 1 as outlined at the workshop.

When the Transmission Operator files for a tariff we would expect that a variety of products would be offered at a variety of rates. Firm and non-firm transmission would be two obvious products, but other variations may also deserve consideration including a separate tariff for transmission customers who have paid to construct their own transmission lines and continue to pay maintenance and property taxes on those lines plus suffer the burden of line losses without any relief from the current transmission rate structure.

The way that the transmission tariff is ultimately developed is of key interest to industrial customers. The high firm tariffs under the existing WTS tariff could break potential bilateral deals with IPP's and others, particularly if current access rules are maintained where large Powerex Blocks may be number one priority on the system when using non firm tariffs.

Production Curtailment

During the workshop presentation there was repeated discussion of the risk that customers will curtail production under a two step rate and that this is undesirable and needs to be controlled in some fashion. Our view is that this risk is inherent in any two step rate and should be accepted by all involved. In this regulated environment, the industrial customer's entitlement is related to consumption, and curtailment products may be limited.

The Process

BC Hydro needs to be mindful that we need to move the process forward expeditiously. It might be helpful if those developing the proposals spend some time canvassing customers informally on basic principles so that they have a better understanding of the customer perspective. We would be glad to discuss any of these issues at any time on quite short notice.

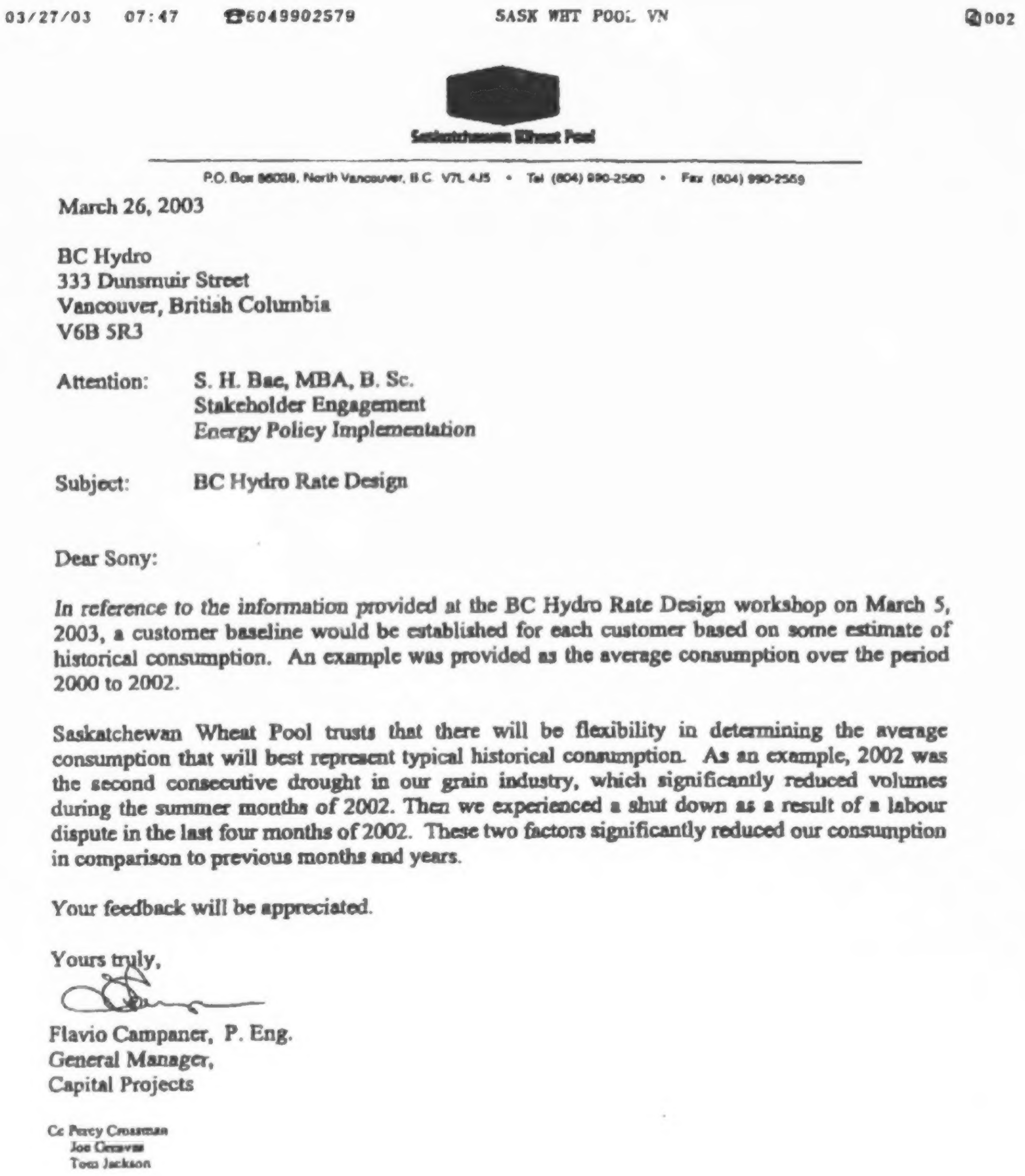
Further Discussions

I understand that our Mr. Dan Potts has made arrangements with you for a meeting between the Joint Industry Electricity Steering Committee and yourself, Catherine Roome and Beverly Van Ruyven at 3 PM on March 13, 2003. We look forward to meeting with you at that time.

Sincerely,

Dal Scott, Chairman
Joint Industry Electricity Steering Committee

CC: Beverly Van Ruyven
Catherine Roome
Secretary – BCUC
Paul Weiringa



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Saskatchewan Wheat Pool

P.O. Box 86038, North Vancouver, B.C. V7L 4J5 • Tel (604) 990-2560 • Fax (604) 990-2569

March 26, 2003

BC Hydro
333 Dunsmuir Street
Vancouver, British Columbia
V6B 5R3

Attention: S. H. Bae, MBA, B. Sc.
Stakeholder Engagement
Energy Policy Implementation

Subject: BC Hydro Rate Design

Dear Sony:

In reference to the information provided at the BC Hydro Rate Design workshop on March 5, 2003, a customer baseline would be established for each customer based on some estimate of historical consumption. An example was provided as the average consumption over the period 2000 to 2002.

Saskatchewan Wheat Pool trusts that there will be flexibility in determining the average consumption that will best represent typical historical consumption. As an example, 2002 was the second consecutive drought in our grain industry, which significantly reduced volumes during the summer months of 2002. Then we experienced a shut down as a result of a labour dispute in the last four months of 2002. These two factors significantly reduced our consumption in comparison to previous months and years.

Your feedback will be appreciated.

Yours truly,

Flavio Campaner, P. Eng.
General Manager,
Capital Projects

Cc Percy Crossman
Joe Cecavas
Tom Jackson

Leader Mining International Inc.

28 March 2003

Sony Bae
Task Leader for External Stakeholder Engagement,
Energy Policy Implementation
BC Hydro
333 Dunsmuir St
Vancouver V6B 5R3

Dear Sony

Leader Mining has reviewed the information available to dateon the Stepped Rates and Access Principles issues, and wishes to respond to BC Hydro.

In discussions with Minister Neufeld, and with his assistant Steve Simons, it has been made very clear to Leader Mining that it's proposed Cogburn Magnesium Project would qualify as a large industrial customer eligible for similar treatment to existing large customers. Leader's concern lies primarily in the lack of clarity regarding provision for new large industrial customers which may require power from BC Hydro's system.

The discussion and presentations regarding the stepped rate design parameters focus particularly on existing customers who, through historical consumption data, have established customer baselines. It is not clear how Tier 1 and Tier 2 rates may be allocated, given that new customers can establish no baseline consumption figure.

The options for establishing such stepped rate structures laid out by BC Hydro should more plainly address this issue of*new* large industrial customers, and we look forward to this being addressed in BC Hydro's submission to the BCUC.

Yours sincerely,

Julian Taylor
Energy Consultant to Leader Mining International Inc.

**Joint Industry Electricity
Steering Committee**

VIA E-MAIL

April 1, 2003

Ms Sony Bae
Task Leader for External Stakeholder Engagement
Energy Policy Implementation
BC Hydro
Vancouver BC

Dear Ms Bae,

On March 14 we received your "Summary of BC Hydro's March 5 Workshop on Stepped Rates & Access Principles." In that Summary you solicit further input from stakeholders and raise several specific issues for consideration. It is the purpose of this letter to convey to BC Hydro management the views of the Joint Industry Electricity Steering Committee (JIESC) members. In addition to this communication, a number of our members will be sharing their particular views with BC Hydro. We are hopeful that this collective input will serve to enhance understanding and assist BC Hydro to develop a presentation to the British Columbia Utilities Commission (BCUC) that will contain proposals acceptable to both BC Hydro and its large industrial customers.

During the development of the BC Energy Policy we were concerned that the policy for the supply of electricity be developed in a manner that preserved the "BC Advantage" for existing customers of BC Hydro through preserving cost based rates for the existing heritage electricity production assets. As major industrial customers, we define the "BC advantage" in electricity as both low costs and low volatility. At the same time, we recognize the need to encourage the ongoing development of a robust IPP Industry and demand side management program in order that BC's future electricity production assets be efficiently acquired.

It is important to us that electricity industry development be done in a balanced manner that will encourage development of the electricity industry without discouraging economic improvement, expansion and development in other industries. We believe that the BC Energy Policy as stated by the government during its unveiling did that and we expressed our direct support and appreciation for the development of that policy.

We are concerned that the rate structure concepts developed by BC Hydro in the March 5 workshop may encourage Demand Side Management and IPP development, but does so at the expense of discouraging economic development and expansion of existing industry. BC Hydro's notion of setting the second tier rate at the marginal cost of supply, either market price of electricity or the LRIC of a natural gas fired generation plant in California, could be very unsettling to someone looking to invest in power consuming facilities in BC.

We believe that it is possible to develop a balanced rate structure based on cost, that accomplishes the BC Government's objectives, BC Hydro's objectives and our objectives without discouraging economic development. We look to working closely with your group to encourage the development of such a proposal.

The March 5 workshop and the Summary largely deal with the issue of stepped rates **for industrial customers**. We trust BC Hydro recognizes that the stakeholders affected by the stepped rates are the industrial customers and that their views should receive predominant consideration. As outlined in the Energy Policy, the objective of stepped rates is to provide additional incentive for conservation and also provide a market for electric power that could be served by Independent Power Producers (IPP's). However, this rate proposal also needs to be aligned with the other objectives of the Energy Policy such as a return to cost based regulation by the BC Utilities Commission, the preservation of cost based rates as an advantage for BC businesses, **and the policy directive rejecting the use of market prices to establish rates for customers.**

We continue to believe and insist that the appropriate integration of all these policies requires a two step rate with the first step based on actual costs incurred by BC Hydro in obtaining electric power from low cost, Heritage sources and the second step based on the average actual costs of obtaining the required power from non-Heritage sources

With that introduction we will now move on to specific comments on the Summary. We have not attempted to provide comments on every issue of concern but have focused on those believed to be of most significance.

General Comments

The JIESC members who attended the conference uniformly agree that the Summary does not reflect the overwhelming lack of support for BC Hydro's proposals for stepped rates. A major concern of the industrial customers is that the BC Hydro proposal will produce rates below cost, a structure we feel will not be politically sustainable. Further the use of market or marginal cost as a proxy for the Tier 2 price was rejected by the industrial customers, yet the summary seems to ignore the response at the workshop and further justifies BC Hydro's proposals.

Market Prices

Page 4 of the Summary contains the following statement: "BC Hydro stated that in order to encourage efficient conservation, DSM investment and IPP access, the Tier Two rate should be based on some form of forward market price rather than historical cost." This statement is not consistent with the Energy Policy document.

Again we point out that there is no market for electric power in BC. This issue was argued extensively with the Provincial Government during the development of the Energy Policy, a policy that rejects market prices as a basis for developing rates for consumers. The new Energy Policy requires a return to cost based rates regulated by BCUC. Therefore it is our firm belief that the appropriate basis for the two step rate is some logical division of low and high cost sources of electric power that are or will be a part of the resources supplying BC consumers.

Stepped Rate Versus RTP Design

The RTP design could result in industrial customers purchasing power from BC Hydro at a very low energy charge, even possibly less than zero. This just won't work over the long term, as it would not be sustainable. The cost based stepped rate is necessary to keep rates at a level that will be seen as fair and reasonable to all customer classes.

CBL Design

We support establishing the CBL for individual industrial customers based on historic consumption with allowance for anomalies to ensure a realistic estimate of the base for future consumption.

The Energy Policy promotes protection of low cost power as a BC advantage. The overall objective is to improve the economic future of BC by retaining existing industry and providing opportunities for further growth of power consuming industries in BC. The CBL will be used to define the quantity of power available to existing customers under step one of a stepped rate. In order to have a level playing field for new and expanding businesses, it will be necessary to develop a CBL for new businesses as well as increasing the CBL for a business undergoing significant expansion.

Determining Market Price

In the Highlights attached to the Summary, the opening sentence states in section 3 entitled "Determining the Market Energy Price states flatly that "The market energy price will be used to set the stepped rate Tier Two price…" It is our understanding that no decision has yet been made that would determine how the Tier Two price is established.

Since there is no market for electric power in BC currently and it is unlikely there will be a market in the foreseeable future, there is no way to determine a market price in BC.

Therefore we favor an approach based on costs, not on market. We also favor rates that are insulated from short-term volatility. All these concerns support **cost based rates.**

Clean Energy

The Provincial Government has committed to a goal of 50% of new energy sources that will meet the BC definition of clean sources of power. At the same time the expectation is that the impact on the cost of electric power will be minimal. Consumers who are interested in supporting the development of clean energy should be offered an opportunity to buy clean energy at cost based premium. The amount of clean power purchased by BC Hydro should not exceed the demand from customers who are willing to pay, either in BC or external to BC.

Bill Versus Revenue Neutral

BC Hydro seems to place significant weight on the bill neutral requirement in the Energy Policy document. Industrial consumers also consider this a significant starting point, but we realize it is a point in time concept when the rates are converted from the current 1821 tariff to the stepped rate design. A revenue requirement application will adjust the new rates very shortly after they are developed.

It would be our preference that the new rates be cost based at the outset, rather than based on a Tier 2 marginal LRIC cost or market rate, with the Tier 1 rate merely calculated to drive the bill to neutral. If new rates are established without a firm economic base, we will lose transparency in how these rates are adjusted over time. This will create problems for all customer classes, not just the industrials.

Level Playing Field for IPP's

The Energy Policy restricts BC Hydro from building new generation with the exception of enhancements to existing facilities. This limits load growth requirements to be met from IPP generation, or DSM and CBG programs. The BC Hydro marginal market rate construction may have the perverse effect of encouraging uneconomic customer programs to the detriment of IPPs. If Tier 2 rates are set at the average cost of supply, then BC Hydro can acquire capacity on a competitive RFP basis from either customers or IPPs. This provides the opportunity for IPPs to achieve a level playing field.

We are concerned that BC Hydro is pushing too far too quick with the marginal rate concept, and trying to create a market in BC overnight. Over time, the balance of power provided to BC consumers will switch to non-Heritage generation, and that will gradually lead to a power market in BC where there can be both retail and wholesale competition at the margin. This should evolve, not be forced.

Again, we thank you for this opportunity to provide input and trust there will be further opportunities to discuss these and other issues as the process proceeds.

Sincerely,

Dal Scott, Chairman
Joint Industry Electricity Steering Committee

CC: Beverly Van Ruyven
Catherine Roome
Secretary – BCUC
Paul Weiringa

Aquila

George Isherwood
Regulatory Affairs Executive

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george.isherwood@aquila.com

April 21, 2003

Via Email
Original via mail

Ms. Catherine Roome
Project Manager, Energy Policy Implementation
BC Hydro and Power Authority
333 Dunsmuir Street - 17th Floor
Vancouver, BC V6B 5R3

Dear Ms. Roome:

Re: ***Heritage Contract, Stepped Rates and Access Principles***

Aquila Networks Canada (British Columbia) Ltd. ("Aquila") supplies some 130,000 customers directly and indirectly in the southern interior of British Columbia. Aquila's customers are primarily residential and commercial, with very little large industrial load. The majority of the large industrial load faces market prices for marginal purchases. Aquila is a fully integrated utility providing Generation, Transmission, and Distribution services.

Electricity is supplied to customers from Company owned hydroelectric resources, as well as major power purchase contracts with Columbia Power Corporation, and BC Hydro under the terms of the Power Purchase Agreement ("PPA"). In addition, in 2003 Aquila forecasted that it would purchase 173 MW, or 26% of its requirements from the wholesale power market.

Aquila's contract with BC Hydro provides for supply at transmission voltage to a maximum of 200 MW. The terms of supply by BC Hydro were the result of several British Columbia Utilities Commission ("Commission") processes, and utility to utility negotiations culminating in the current Power Purchase Agreement. The PPA recognized directions contained in Commission Order G-27-93. The Commission ensured that the PPA and terms and conditions thereof were reflective of fair market arrangements. The PPA expires in September 2013

The Heritage Contract Terms of Reference, in particular Section Four, provide that the Commission shall make recommendations regarding stepped rate and access principles for transmission rate customers. The BC Government's Energy Plan mandated stepped rates as a means of exposing large customers to a "market" price and thus enhancing economic efficiency.

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Aquila has been exposed to true market pricing for many years, and the necessity for efficient use of electricity is embodied in our best in class Energy Management services. Aquila does not believe that the application of an artificial market price, through stepped rates, is reasonable or beneficial in Aquila's circumstances. This position is shared by Aquila's wholesale customers, who are in turn, distribution utilities that have opted to "subcontract" the power aggregation function to Aquila.

Aquila supports the Energy Plan, but believes its implementation must recognize the unique position of distribution utilities and their ultimate customers. Aquila requests that this letter be recognized in BC Hydro's recommendations to be filed with the Commission by April 30, 2003.

Yours truly,

(original signed by G. Isherwood)

George Isherwood
Regulatory Affairs Executive

cc: Rod Carle, IMEU
Bev Van Ruyven, BC Hydro

CORPORATION OF THE CITY OF NEW WESTMINSTER

April 25, 2003

BY FAX: 604-623-4430

Ms. Bev Van Ruyven
Vice-President Distribution Line of Business
BC Hydro
6911 Southpoint Drive
Burnaby, B.C. V3N 4X8

Dear Ms. Van Ruyven:

Re: Heritage Contract for B.C. Hydro's Existing Generation Resources, Stepped Rates and Transmission Access

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The City of New Westminster has operated an electric distribution utility for our ratepayers for over 100 years, and has been a BC Hydro customer for as long as BC Hydro has been in existance. The City, as an electric distribution utility, is similar to BC Hydro's Distribution Line of Business, in that the City has an obligation to serve, to offer rates that are fair, just, and reasonable, and to provide smooth, stable and predictable rate changes.

The regulatory processes, whereby the provincial government will implement its 2002 Energy Plan, have begun with the Terms of Reference for the Heritage Contract, addressing the assignation of energy from BC Hydro's existing embedded cost energy resources. The terms specifically allocate the output of those resources to BC Hydro's Distribution Line of Business. The City wishes for similar treatment to that of BC Hydro's Distribution Line of Business in being able to retain the benefit of the heritage resources as a fixed quantity of energy, to be determined, in order to provide low cost electricity to meet existing load and growth within its service area.

The Energy Task Force Recommendation 5.01, aimed at developing a wholesale electricity market in BC fails to recognize that, as a wholesale utility, the City has had access to market power since the BC Utilities Commission approval of BC Hydro's Wholesale Transmission Service Application (April 1998) and Access Principles (January 2001). Policy Action #14, advocating stepped rates for BC Hydro transmission rate customers does not, therefore, include the City, as an existing BC Hydro wholesale customer.

The City of New Westminster believes that to successfully implement the Energy Plan, there must be fair allocation of the Heritage benefits to the electricity ratepayers of all electric distribution utilities in BC.

Yours truly,

Paul Daminato,
City Administrator

copy: Ms. Catherine Roome, BC Hydro

Office of the City Administrator 511 Royal Avenue, New Westminster, BC V3L 1H9
Telephone: 604 527-4551 Facsimile: 604 527-4599